BC hydro

Electricity Plan

1991 Update

Summary

March 1991

LEGISLATIVE LIBRARY
VICTORIA, B.C.

BC
B685
B'C5833
1991
c.3

Canadian Cataloguing in Publication Data

B.C. Hydro.

An introduction to the 1990 electricity plan

ISBN 0-7726-1130-0

1. Electric power - British Columbia - Planning.
I. Title.

HD9685.C33B322 1990 333.79'32'09711 C90-092148-X

91-06531/

INTRODUCTION

This summary of the **B.C. Hydro Electricity Plan - 1991 Update** reflects an evolving perspective on future supply and demand options, which incorporates new provincial and corporate policy directions on the role of the private sector, the environment, and efficient energy use. Gains continue to be made on the supply outlook, through operating efficiencies, innovative demand reduction measures, marketing practices, and promotion of private sector resource development.

REVIEW OF THE YEAR'S EVENTS

New Directions for the 1990's, the Provincial Government's energy policy, was released in November of 1990. It emphasizes efficient use of clean energy, along with reliable, competitively priced supply. B C. Hydro's current directions reflect this policy.

The third annual Electric Energy Public Forum was co-sponsored by B. C. Hydro and two provincial ministries. Lifestyles, the environment and the use of electricity were discussed.

A Coordination Agreement (Non-Treaty Storage Agreement) was signed with the Bonneville Power Authority (BPA) of the U.S. Pacific Northwest. This increased the B.C. Hydro system capability by 750 GW·h/a. B.C. Hydro, Powerex and BPA also signed a 20-year Interconnection and Exchange Agreement to facilitate continued electricity trade between the parties.

Powerex, a wholly-owned subsidiary of B.C. Hydro, sponsored a workshop on the Power Exchange Operation being established to facilitate the exchange of short-term electricity. The official name of Powerex has been changed from B.C. Power Export Corporation to B.C. Power Exchange Corporation to better reflect its mandate.

1990/91 highlights

- New provincial energy policy released
- Coordination and Exchange agreements with BPA signed
- Power Exchange Operation established
- Nine new Power Smart programs launched
- Conservation Potential Review underway
- Peace Site C and Keenleyside shelf-ready
- Rate Design Application submitted

Power Smart Inc. was established as a wholly-owned subsidiary of B.C. Hydro to provide a national energy efficiency focus with customers, governments, manufacturers, distributors, retailers and energy-related associations.

Power Smart launched two residential, four commercial and three industrial programs during the year.

A Collaborative process to determine electricity conservation potential in the B.C. Hydro and West Kootenay Power service areas was launched. Representation includes industry, residential and commercial sectors, environmental groups, B.C. municipalities and the two utilities.

Reinforcements to the transmission system were completed to increase power transfer capability into the Lower Mainland, to extend service to new industrial customers, and to reduce transmission losses.

B.C. Hydro announced that the Site C and Keenleyside hydroelectric projects were being brought to shelf-ready status.

The B.C. Ministry of Energy, Mines and Petroleum Resources announced that the

project screening and evaluation process for small (less than 5 MW) projects will be streamlined.

A Rate Design Application was submitted to the B.C. Utilities Commission (BCUC). B.C. Hydro proposes to modify the existing rate structure to encourage efficiency in the production and utilization of electricity.

B.C. Hydro introduced an environmental credit into the project screening process. The cost of projects with little or no environmental impact can be reduced by as much as 15 percent for comparison to Hydro's calculated cost of new electricity supply. The BCUC agreed that this was "a good start towards the reflection of the full environmental benefits or costs of each resource alternative". This is independent of the premium awarded by the provincial government to projects which alleviate environmental impacts.

DEMAND/SUPPLY OUTLOOK

Since publication of the 1990 Electricity Plan, a number of changes have taken place to both the demand and supply outlook. These changes have influenced B.C. Hydro's development strategy.

In the past, meeting forecast annual energy requirements has tended to dominate the scheduling of new resources. However, B.C. Hydro is now relying on an increasing variety of resource options, many of which supply primarily energy with little or no dependable capacity. This will result in a much closer balance between capacity demands and supplies. Transmission capacity constraints have also become a critical component in B.C. Hydro's ability to serve large demands in the Lower Mainland and Vancouver Island.

ELECTRICITY DEMAND FORECAST

The primary purpose of the demand forecast is to project future energy and peak demands to guide resource management and budget planning in the short term and resource and transmission planning in the long term.

A short-term demand forecast was prepared in September 1990, covering the five year period to 1995/96, to address changing conditions in the provincial economic outlook. Slower demand growth was projected for the first three years of the forecast, while long-term projections remained unchanged from the 1990 Electricity Plan.

Exhibit 1 shows the Probable Energy Forecast and the Peak Forecast including West Kootenay Power and Skagit Valley Treaty commitments. Demand for energy is forecast to grow from 45 610 GW·h in 1990/91 to 54 600 GW·h for 1995/96, at an annual growth rate of 3.7%, and to about 75 000 GW·h by 2010. Peak demand is projected to grow from 8 225 MW in 1990/91 to 9 660 MW in 1995/96 at an annual rate of 3.3%, and to about 13 600 MW by 2010.

The forecast is based on analysis of economic, demographic and energy transaction data. Profiles of changing energy market conditions and business outlooks are developed to produce potential demand growth scenarios. Flexibility in meeting alternative demand growth scenarios provides a base for planning decisions and is an important criterion by which development options are judged.

The electricity forecast is based on economic projections from the Ministry of Finance and Corporate Relations, and on consultant studies of key industries. The economy is expected to enter a period of moderate growth over the next five years with a projected average annual growth rate of 2.9% The population growth rate has increased from 1.6% to 2.1% per year. The provincial population is forecast to rise to 3 450 700 by 1995.

RESOURCE OPTIONS

Power Smart

The Power Smart commitment has expanded since last year, from 4 300 GW·h/a to 6 460 GW·h/a (adjusted for avoided transmission losses) and about 1 200 MW in peak reduction by the year 2010. B.C. Hydro's projected investment is being increased from $334 million to $600 million over the next 20 years.

Estimates of Power Smart savings are reviewed on an ongoing basis. The original estimates were purposefully conservative. The increase in Power Smart projections is supported by the favourable customer response to launched programs and improved information about applied demand-side management. The BCUC continues to review the prudency of Power Smart programs.

Improvements to Existing Facilities

The Resource Smart program, which is intended to ensure most efficient use of B.C. Hydro's existing facilities, is projected to increase supply to the system by about 23 MW and 690 GW·h/a by 2000. Five major Resource Smart projects which are part of the Lower Columbia Development are identified as economically competitive after 2000. These are the installation of power facilities at Keenleyside and Duncan dams, Seven Mile Unit 4, and expansion of the generation facilities at Cominco's existing Waneta and Brilliant dams.

Feasibility studies are underway for Waneta and are to be initiated in 1992/93 for Brilliant. These two projects would allow the streamflow regulation capability of existing upstream dams to be fully utilized. In turn, these projects would allow increased operating flexibility and dependable capacity at the upstream plants.

The potential contribution of the Burrard Thermal plant has been increased to reflect purchase of competitively priced natural gas in the spot market. In addition, a small firm gas contract has been in place in recent years at Burrard to operate the plant to improve the voltage stability of the transmission system. As a result, Burrard's capability has been uprated from 0 MW to 40 MW of dependable capacity and from 3 430 GW·h to 5 270 GW·h of annual energy.

RESOURCE OPTIONS

- Power Smart
- Improvements to existing facilities
- Coordination and major purchases
- Private power
- Columbia River Treaty Downstream Benefits
- Hydroelectric generation
- Thermal generation
- Alternative energy and emerging technologies

Coordination and Major Purchases

In addition to current coordination and purchase agreements with B.C. Hydro, Alcan may have available up to 1 200 GW·h/a and 200 MW surplus to their needs.

BPA and B.C. Hydro are now considering exploring additional opportunities for coordinated operation which would use B.C. Hydro's reservoir storage on the Peace and Columbia River systems. These discussions will be contingent on the outcome of studies currently underway with Alberta on the Peace River system.

Agreement on the principles for coordinated operation, reserve sharing and emergency support between B.C. Hydro and the Alberta Interconnected System is expected this year. However, since studies were completed in 1989, the development strategies for both systems have been modified reducing the potential benefits available from coordination. Nevertheless, support from

Alberta would allow B.C. Hydro to reduce its reserve requirement by 400 MW. TransAlta is negotiating the purchase of 200 MW of capacity from B.C. Hydro and transmission access to U.S. markets.

Private Power Generation

It is anticipated that customer self-generation and purchases from independent power producers (IPPs) achieved through a competitive market will lower the cost of electricity in B.C. Approximately 5 200 GW·h/a of new electricity could be available by the end of the decade. Most of this is expected to come from the cogeneration of electricity with steam and the coincident disposal of woodwaste.

The provincial government has also expressed support for a gas-fired generating station on Vancouver Island which could be in the order of 200 MW. An evaluation of this project has not yet been completed and it has not been incorporated into this Electricity Plan Update.

Columbia River Treaty Downstream Benefits (DSBs)

Since the DSBs belong to the province, the government must decide how to use or allocate this resource. It is assumed that the DSBs would directly or indirectly be used to meet B.C. Hydro's demand forecast. However, alternative planning scenarios considered the possibility that all or some of the DSBs would be used to serve demands not presently included in the demand forecast.

The contribution from the DSBs is also substantially affected by the rate of demand growth in the U.S. Pacific Northwest (PNW). As electricity demand in the PNW increases, U.S. utilities will likely have to add more thermal resources, which would decrease their dependence on streamflow regulation provided by the Canadian Treaty dams. The energy component of the DSBs could double if the PNW experienced low demand growth as opposed to high growth.

The capacity credit component of the DSBs, expected to be about 1 100 MW, is not sensitive to demand growth in the PNW.

New Hydroelectric Development

The 900 MW Peace Site C project and the 240 MW Keenleyside project on the Columbia River have reached shelf-ready status and can serve B.C. Hydro as valuable contingency options.

The Lower Columbia Development also includes the 275 MW Murphy Creek and 250 MW Border projects. Unlike the five Resource Smart projects on the Lower Columbia these would require new dams. Investigations for these projects have been curtailed.

Thermal and Alternative Energy

Natural gas is currently the fuel of choice for thermal power generation among IPPs, but future gas prices are uncertain. It is expected that restrictions on the disposal of all waste products, including wood, will encourage their use for by-product power generation among self-generators and IPPs.

B.C. Hydro will continue to monitor developments in alternative energy and emerging technologies. For example, recent developments in fuel cell technology are being scrutinized for potential application. Small hydro development is being pursued by the private sector, and extensive investigations are being carried out for geothermal energy. The remaining resources are not included in this Electricity Plan Update because of uncertainties regarding cost and/or availability.

TRANSMISSION REQUIREMENTS

Planned transmission developments continue to be driven by the imbalance between demand and supply in the Lower Mainland and Vancouver Island. The transmission system into the Lower Mainland is presently operating near its capacity and

voltage stability limits. Also, most future growth is projected for these areas.

Generation by IPPs and customer self-generation as well as increased coordination and purchase agreements with other utilities also affect transmission requirements. The capacity, the delivery point and the dispositon of the DSBs could significantly affect transmission requirements.

DEVELOPMENT STRATEGY

The selection of resources for the Electricity Plan is done on the basis of minimizing total long-term costs of acquisition and operation. However, each option is also evaluated with respect to other criteria such as availability, public acceptability, socio-economic and environmental impacts, uncertainty and transmission impacts. This update reflects the same resource development priority established in the 1990 Electricity Plan:

- Power Smart
- Coordination and Purchases
- Resource Smart
- IPPs and self-generation
- New hydro in developed river basins
- New hydro in undeveloped river basins

Exhibits 2 and 3 detail how B.C. Hydro plans to meet energy and capacity requirements over the next 20 years.

MEETING ENERGY NEEDS

Twelve month sales to February 1991 were 5.0% higher than for the same period the year before. Actual demands exceeded forecasts for all sectors. However, some softening is becoming apparent in sales in several areas.

In addition to existing B.C. Hydro facilities and judicious use of non-firm supplies, energy demand growth through the mid 1990's will be met through committed and budgeted resources such as ongoing Power Smart and Resource Smart initiatives; purchases of 1 700 GW·h/a from IPPs; purchases and coordination with Alcan totalling 2 770 GW·h/a; and further demand reductions of 3 500 GW·h/a from customer self-generation.

Studies indicate that major new hydro facilities may be needed prior to 2005 only if actual demand growth is substantially higher than currently projected, or other options do not materialize. B.C. Hydro now plans to meet energy requirements through 2005 by expansion of the Power Smart and self-generation initiatives, and the DSBs.

The Plan assumes that the new resources required in the years 2005 through 2010 could include Seven Mile Unit 4, Waneta and Brilliant, along with other projects which could be undertaken by B.C. Hydro or IPPs, totalling about 11 000 GW·h/a.

MEETING CAPACITY DEMANDS

A record high peak demand of 8 225 MW occurred in December 1990. This is expected to grow by 3.3% per year over the next five years. Assuming 400 MW of reserve sharing is negotiated with Alberta, the peak load carrying capability of the existing system is about 8 900 MW.

Through the mid-1990's, the forecast increase in capacity demand will be met with 250 MW from IPP projects and up to 590 MW from the Alcan purchase and coordination agreement. The DSBs, Seven Mile Unit 4, Waneta, Brilliant plus IPPs would provide another 3 600 MW by 2010.

An additional 1 700 MW could be obtained by installing units 5 and 6 at Revelstoke and Mica. This would complete the work which was authorized for these projects under the terms of their Water Licences.

TRANSMISSION DEVELOPMENT STRATEGY

Power transfer capability to the Lower Mainland and Vancouver Island will continue to be the dominant consideration for transmission development.

Completion of the American Creek series capacitor station near Hope provided the most recent increase in transmission capacity into the Lower Mainland. In addition, a second line is proposed between Kelly Lake and Cheekye Substations. This would be the first 500 kV line constructed into the Lower Mainland in 20 years. A new line from Nicola Substation into the Lower Mainland may also be needed by 1999 to maintain system reliability.

Elsewhere, the existing 500 kV lines from Williston to Kelly Lake are being upgraded. Voltage control equipment is planned at Dunsmuir Substation on Vancouver Island in 1993, and at Ingledow Substation in Surrey in 1997.

Future availability of transmission corridors into the Lower Mainland and Vancouver Island continues to be a major concern.

RISK MANAGEMENT

Several significant contingencies have been considered to cover demand and resource uncertainties in the long-term. If slower demand growth occurs, B.C. Hydro could further delay commitments to new projects, lower incentives to Power Smart and self-generation projects, or market additional energy surpluses. To meet higher than expected demands, shelf-ready projects could be called on, such as Site C. It may also be attractive to advance the scheduling of some Lower Columbia projects.

Since the development strategy proposes to significantly increase reliance on resources not directly controlled by the utility, the various risks associated with these supply sources must be managed. For example, unavailability of the DSBs would require advancing new resources by two to three years. Shelf-ready projects could provide a valuable hedge against any undue risk exposure resulting from heavy reliance on IPPs in the long-term.

ELECTRICITY TRADE

The Powerex Power Exchange Operation (PEO) and B.C. Hydro's proposed Wheeling Policy will both contribute to the implementation of the development strategy and optimize benefits to B.C. Hydro and its customers from the efficient management of electric system resources.

Transmission wheeling is more than moving electricity from one system to another through a third party. It can provide services such as load shaping, storage, backup and increased reliability. Currently, B. C. Hydro negotiates long-term wheeling contracts with clients. The PEO provides utility and non-utility electricity suppliers and consumers access to a market-priced short-term exchange of energy services.

ACTION PLAN

The following actions will be taken during 1991/92:

Power Smart Programs

About $53 million has been allocated for these programs in 1991/92. The costs and practicality of achieving program targets will continue to be evaluated. Detailed analysis of the impact of these programs on B.C. Hydro's electric system operation will be undertaken.

Phase One of the Collaborative on Conservation Potential should be complete by early 1992. This will define the technological, social and economic potential. Phase Two will examine the achievable potential.

Resource Smart

A capital budget of $10.5 million plus $1.5 million for studies and investigations has been allocated for 1991/92. Discussions with Cominco concerning Waneta and Brilliant expansions will continue.

A decision on the investments required to optimize the future operation of Burrard Thermal will be sought.

Purchases and Coordination

B.C. Hydro will pursue studies of further coordinated operation of the Columbia River system with BPA. A potential sale of 200 MW of capacity to TransAlta and a similar amount of transmission access to the U.S. should be resolved during the year.

Independent Power Producers

B.C. Hydro expects to finalize discussions with IPPs for over 100 MW of new capacity. In additon, an RFP should be issued for small thermal generation covering woodwaste and landfill gas projects.

Self-Generation

Negotiations will continue with a number of self-generation proponents. B.C. Hydro will continue to actively assist its major customers to evaluate their self-generation potential and to encourage development in this area.

New Capacity

The potential for capacity benefits from installation of additional units at Mica and Revelstoke, or the advancement of Lower Columbia Resource Smart projects, will be assessed.

Alternative Energy

B.C. Hydro will be reviewing its alternative energy strategy to determine the future role of these resources. Funding of a fuel cell demonstration program may be undertaken.

Major Transmission Projects

An application for an Energy Project Certificate for the second Kelly Lake to Cheekeye 500 kV line will be submitted in April. Total expenditures of about $167 million are budgeted in 1991/92 for transmission system reinforcements.

Rate Design

A public hearing into B.C. Hydro's proposed modifications to the existing rate structure will be held during 1991.

Export Activities

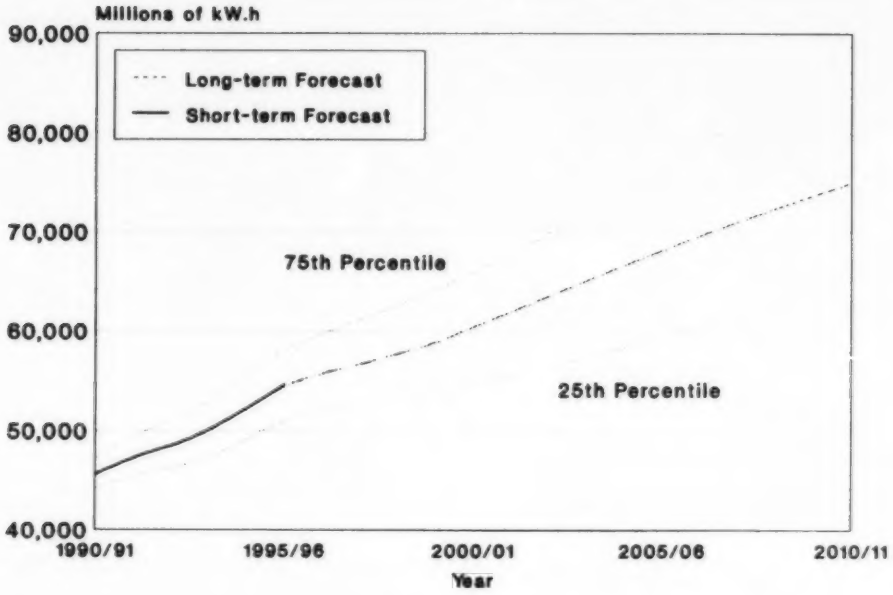
B.C. Hydro and Washington Water Power Company will continue planning a 230 kV transmission intertie. Contruction is subject to Powerex and WWP establishing sales agreements.

Public Consultation

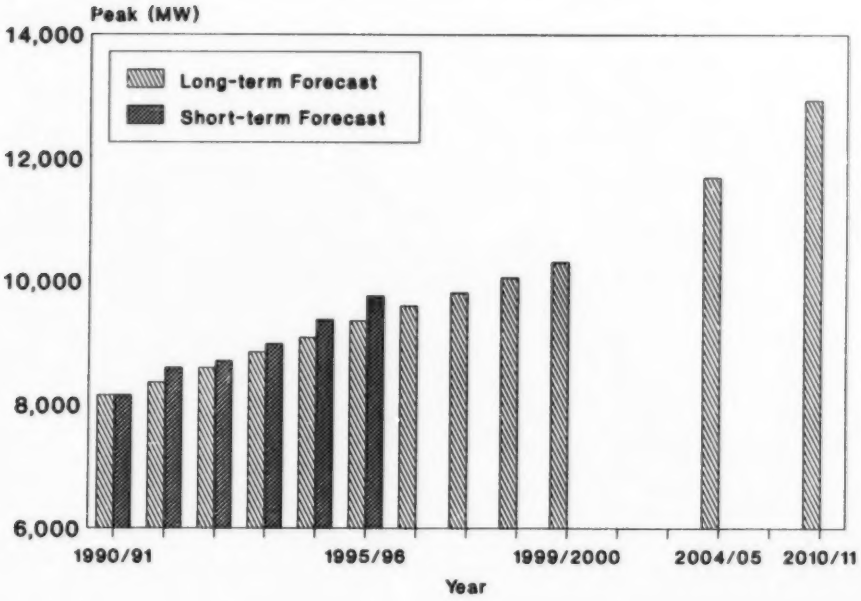
The "Electricity in the Lower Mainland Choices for the Future" program, an initiative to involve Lower Mainland leaders, planners and the public in examining the electrical needs and resources options for the region will take place during 1991.

Exhibit 1

ENERGY FORECASTS



PEAK FORECASTS



FORECAST ENERGY DEMAND AND FIRM SUPPLY
Millions of kW.h

	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	05/06	10/11
PROBABLE DEMAND	**47420**	**48370**	**49940**	**52200**	**54580**	**55700**	**56570**	**57700**	**58710**	**60420**	**68130**	**74970**
Power Smart	510	930	1430	1990	2580	3210	3710	4110	4480	4850	5890	6540
Self–generation	0	0	225	820	1710	2610	3500	3500	3500	3500	3500	3500
NET PROBABLE	**46910**	**47440**	**48285**	**49390**	**50290**	**49880**	**49360**	**50090**	**50730**	**52070**	**58740**	**64930**
FIRM SUPPLY												
Existing Hydro	43520	43520	43520	43520	43520	43520	43520	43520	43520	43520	43520	43520
Thermal	5820	5820	5820	5820	5820	5820	5820	5820	5820	5820	5820	550
Resource Smart	160	200	340	370	470	540	630	690	690	690	690	690
Purchases & Coordination	2265	1865	1465	1595	2770	2770	2770	2770	2770	2770	2770	2770
Signed IPP's	5	65	940	1740	1720	1720	1740	1670	1710	1740	1710	1740
Return of DSB's	0	0	0	0	0	0	0	480	2790	2760	4710	4510
New Resources	0	0	0	0	0	0	0	0	0	0	160	11520
TOTAL FIRM SUPPLY	**51770**	**51470**	**52085**	**53045**	**54300**	**54370**	**54480**	**54950**	**57300**	**57300**	**59380**	**65300**
SUPPLY/DEMAND BALANCE												
25th PERCENTILE *	6680	6110	6265	6355	6960	7640	8540	8710	11370	10690	9500	10380
PROBABLE	**4860**	**4030**	**3800**	**3655**	**4010**	**4490**	**5120**	**4860**	**6570**	**5230**	**640**	**370**
75th PERCENTILE *	2720	1700	1065	525	470	590	790	−30	1040	−570	−8230	−14150

* NOTE : These values overstate differences between supply and demand because the Resource Development Plan will be adjusted in response to higher or lower growth trends as they are detected.

FORECAST PEAK DEMAND AND CAPACITY SUPPLY
Megawatts

	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	05/06	10/11
PROBABLE DEMAND *	**8590**	**8710**	**8860**	**9370**	**9760**	**10010**	**10260**	**10520**	**10760**	**11060**	**12380**	**13630**
Power Smart	100	170	270	370	480	600	690	760	830	900	1060	1210
Self – Generation	0	0	30	110	230	350	470	470	470	470	470	470
NET PROBABLE	**8490**	**8540**	**8560**	**8890**	**9050**	**9060**	**9100**	**9290**	**9460**	**9690**	**10850**	**11850**
DEPENDABLE CAPACITY												
Existing Hydro	9293	9293	9293	9293	9293	9293	9293	9293	9293	9293	9293	9293
Thermal	180	180	180	180	180	180	180	180	180	180	180	140
Resource Smart	0	0	0	0	15	15	23	23	23	23	395	735
Purchases and Coordination	76	76	76	76	590	590	590	590	590	590	590	590
Signed IPP's	2	15	225	251	251	251	251	251	251	251	251	251
Return of DSBs	0	0	0	0	0	0	0	100	600	600	1100	1100
New Resources	0	0	0	0	0	0	0	0	0	0	0	1750
TOTAL DEPENDABLE CAPACITY	**9551**	**9564**	**9774**	**9800**	**10329**	**10329**	**10337**	**10437**	**10937**	**10937**	**11809**	**13859**
PEAK LOAD CARRYING CAPABILITY **	**8900**	**8910**	**9040**	**9140**	**9610**	**9610**	**9610**	**9710**	**10170**	**10170**	**10960**	**12890**
SUPPLY/DEMAND BALANCE												
25th PERCENTILE ***	790	820	840	800	1150	1180	1230	1240	1640	1530	1560	2520
PROBABLE	**410**	**370**	**360**	**250**	**560**	**550**	**510**	**420**	**710**	**480**	**130**	**940**
75th PERCENTILE ***	0	−120	−210	−380	−150	−250	−290	−450	−190	−470	−1440	−1810

NOTES: * The Probable Demand incorporates revisions to estimated WKP&L requirements, and increases of about 100 MW to reflect the maximum expected SCL requirement under the Skagit Valley Treaty.

** Peak Load Carrying Capability is derived from the Total Dependable Capacity by a detailed reliability analysis.

*** These values overstate differences between supply and demand because the Resource Development Plan will be adjusted in response to higher or lower growth trends as they are detected.

BC hydro

Electricity Plan

1991 Update

March 1991

BC
2685
D:E5835
1991
c.3

British Columbia Cataloguing in Publication Data

Main entry under title:
Electricity plan. -- 1990-

Continues: B.C. Hydro. Resource Planning. Twenty-year resource plan for the period .... ISSN 0843-5707
ISSN 1180-2561

1. B.C. Hydro. 2. Electric power - British Columbia - Planning. I. B.C. Hydro. Resource Planning.

HD9685.C33B322 333.79'32'09711

ELECTRICITY PLAN

1991 UPDATE

TABLE OF CONTENTS

EXECUTIVE SUMMARY

1.0 INTRODUCTION 1

1.1 Purpose of Update 1
1.2 Provincial Energy Policy
1.3 Review of the Year's Events 1
1.4 Demand/supply Outlook 2
1.5 The Environment 3

2.0 ELECTRICITY DEMAND FORECAST 4

3.0 RESOURCE OPTIONS 7

3.1 Power Smart 7
3.2 Improvements to Existing Facilities 10
3.3 Coordination and Major Purchases 12
3.4 Private Power Generation 12
3.5 Columbia River Downstream Benefits 14
3.6 New Hydroelectric Development 15
3.7 Thermal and Alternative Energy 15

4.0 DEVELOPMENT STRATEGY 18

4.1 Short-Term Outlook 18
4.2 Long-term Strategy 18
4.3 Alternative Scenarios 25
4.4 Electricity Trade 25

5.0 TRANSMISSION DEVELOPMENT STRATEGY 26

6.0 RISK MANAGEMENT 29

7.0 ACTION PLAN FOR 1991/92 31

EXECUTIVE SUMMARY

This document is the 1991 update to the 'B.C. Hydro 1990 Electricity Plan'. It reflects an evolving perspective on future supply and demand options, which incorporates new provincial and corporate policy directions on the role of the private sector, the environment, and efficient energy use. Gains continue to be made on the supply outlook, through operating efficiencies, innovative demand reduction measures, marketing practices, and promotion of private sector resource development.

Since publication of the 1990 Electricity Plan, a number of changes have taken place to both the demand and supply outlook, notably:

- although demands again exceeded the forecast for 1990, sales over the next three years are expected to be below previous projections, while no change is anticipated for the long term. Additional 14 600 GW·h/a and 2 800 MW of peak capacity will be required by the year 2000.

- higher contributions are projected from the private sector and Power Smart programs: an approximate combined increase of 3 700 GW·h/a and 250 MW by 2000.

- the Burrard Thermal plant may increase its energy contribution by up to 1 800 GW·h/a through the purchase of natural gas on the spot market.

- the Peace Site C and Keenleyside projects have been brought to "shelf-ready" status, to proceed as needed.

- lower non-firm purchases from TransAlta are now anticipated.

- capacity supply and demand in B.C. Hydro's system is closer to balance than previously anticipated.

B.C. Hydro's resource development priority has not changed from that identified in the 1990 Plan. Power Smart, coordination and purchases, Resource Smart, private sector generation, all precede new hydro generation in developed and undeveloped river basins, all other things being essentially equal. Commitments and budgeted contributions from the first four initiatives should be sufficient to meet forecast demands until almost the turn of the century, when the Canadian entitlement of the Columbia River downstream benefits will begin reverting to B.C.

Under current demand projections, no new generation facilities appear to be required until about 2005, at which time additions to existing Lower Columbia stations are proposed for development. Potential economic sources to meet additional capacity requirements are also being examined, in particular in view of changing resource supply characteristics.

Planned transmission developments continue to be driven by the imbalance between demand and supply in the Lower Mainland and Vancouver Island areas, where 70% of future growth is projected.

Focus for planning activity during 1991 will be on the market outlook for capacity requirements, and on potential alternatives available; added emphasis on regional forecasting and planning; evaluation of potential impacts of demand reduction options on the B.C. Hydro system; review of actions required towards reducing project lead times for additional options while maintaining shelf-ready status for larger projects.

Preparation of Quarterly review updates to the Electricity Plan will continue, as they are intended to ensure that adjustments can be made and action taken if required, in response to a rapidly changing environment.

1.0 INTRODUCTION

1.1 PURPOSE OF UPDATE

This document is the 1991 update to the 'B.C. Hydro 1990 Electricity Plan'. It reflects an evolving perspective on future supply and demand options, which incorporates new provincial and corporate policy directions on the role of the private sector, the environment, and efficient energy use. Gains continue to be made on the supply outlook, through operating efficiencies, innovative demand reduction measures, marketing practices, and promotion of private sector resource development.

Preparation of Quarterly Review updates, a practice instituted in late 1990, will ensure that the Plan can be adjusted and action taken, if required, in response to the dynamic environment.

1.2 PROVINCIAL ENERGY POLICY

"New Directions for the 1990's", the Provincial Government's energy policy, was released in November of 1990. It emphasizes efficient use of clean energy, along with reliable, competitively priced supply. B.C. Hydro's current directions reflect this policy.

1.3 REVIEW OF THE YEAR'S EVENTS

1990 May

- The Third Annual Electric Energy Forum was held in Prince George. Sponsored by the B.C. Ministry of Energy, Mines and Petroleum Resources, the B.C. Ministry of Environment, and B.C. Hydro, the forum provided attendees with opportunities to discuss lifestyles, the environment and the use of electricity.

July

- Coordination Agreement (Non-Treaty Storage Agreement) with Bonneville Power Administration (BPA) was signed. The Agreement took effect in November.

- Powerex, a wholly-owned subsidiary of B.C. Hydro, sponsored a workshop on the Power Exchange Operation, being established to facilitate the exchange of short-term electricity.

September

- A short-term electricity demand forecast was prepared, covering the five year period to 1995/96 to address changing conditions in the provincial economic outlook.

October

- American Creek Series Capacitor Station north of Hope went into service to increase power transfer capability from the Interior to the Lower Mainland.

November

- Principles for a B.C. Hydro wheeling policy entered formal internal review.

- A 230 kV phase shifting transformer went into service at Nelway Substation to limit "loop flow" of power from Washington state through B.C. Hydro's system, and save on system losses.

- B.C. Hydro and Puget Sound Power and Light (PSPL) suspended planning for a 230 kV intertie between their two systems and began negotiating an agreement with BPA that would give

PSPL greater access to power transmitted over the existing 500 kV intertie connecting the B.C. Hydro and BPA systems.

- Power Smart Incorporated, a wholly-owned subsidiary of B.C. Hydro, was established to promote the initiative across Canada.

December

- Power Smart launched two residential programs, four commercial programs and three industrial programs during the year. BCUC continued prudency review of Power Smart programs.

- Transmission extensions to bulk industrial customers were completed in 1990 to Howe Sound Pulp and Paper at Port Mellon, the Fletcher Challenge Mill at Crofton, Louisiana Pacific at Chetwynd, B.C. Chemicals at Prince George and two Transmountain Pipeline pumping stations at Albreda and Darfield in the North Thompson.

1991 January

- The BCUC indicated its support for the application of a B.C. Hydro environmental credit of up to 15% to total project cost for project screening and evaluation.

- Rate Design Application was submitted to the BCUC.

- B.C. Hydro announced that the Site C and Keenleyside hydroelectric projects were being brought to shelf-ready status.

- B.C. Hydro, Powerex and Bonneville Power Administration signed a 20-year Interconnection and Exchange Agreement to facilitate continued electricity trade between the parties.

- The Lower Mainland Choices for the Future program, an initiative to involve Lower Mainland leaders, planners and the public in examining the electrical needs and resource options for the region was announced.

February

- The B.C. Power Export Corporation was renamed B.C. Power Exchange Corporation, to better reflect its mandate.

- Collaborative on Conservation Potential commenced, with representation from industry, residential and commercial sectors, environmental groups, B.C. municipalities, and West Kootenay Power.

March

- The B.C. Ministry of Energy, Mines and Petroleum Resources announced that they will be streamlining the project screening and evaluation process for small (less than 5 MW) projects.

1.4 DEMAND/SUPPLY OUTLOOK

B.C. Hydro will be relying on an increasing variety of resource options to serve forecast demand growth.

The existing hydroelectric system plus the Burrard Thermal plant currently supply almost all capacity and energy requirements in the B.C. Hydro service area. However, by 1995/96 over 16% of forecast energy and peak demands are expected to be met by a variety of initiatives currently underway, such as purchase and coordination agreements, private sector projects and Power Smart programs.

Regional differences in demand/supply balance and the related transmission capacity

constraints will be a critical component in B.C. Hydro's ability to serve large demand centres in its service area. By 1994/95, peak demand will be almost equal to the system actual capability.

Although interruptible sales are expected to be made throughout the period with some of the non-firm hydro energy which should be available under most water conditions, further demand reductions through Power Smart and industrial self-generation will be required to meet additional forecast growth during the late 1990's.

Since publication of the 1990 Electricity Plan, a number of changes have taken place to both the demand and supply outlook, notably:

- slower demand growth is now forecast over the next three years, but no change from previous projections is anticipated for the long term.

- higher contributions are projected from the private sector and Power Smart programs (2 200 GW·h/a, and 146 MW; 1 540 GW·h/a, and 100 MW increases by 2000, respectively).

- potential increased contribution from the Burrard Thermal plant, through the purchase of natural gas on the spot market.

- lower non-firm purchases from TransAlta are anticipated.

- B.C. Hydro's system peak load carrying capability is about 210 MW lower than previously estimated, even after introduction of modified operating practices.

- the Peace Site C and Keenleyside projects have been brought to "shelf-ready" status, and are ready to proceed as needed.

- issues related to the capacity component of the Downstream Benefits (DSBs), currently assumed to be about 1 100 MW, are under discussion with BPA.

1.5 THE ENVIRONMENT

In the 1990 Electricity Plan, environmental impacts were identified as one of the criteria applied to assessment of options. In November, B.C. Hydro proposed to the BCUC that an environmental **credit** be applied to those projects which would have little or no impact on the environment. The credit, which is determined for each project individually and could be up to 15 percent of the total project cost, is applied for project screening only. This is independent of the provincial government environmental **premiums** awarded to projects which alleviate environmental impacts.

The BCUC agreed that this application was "a good start towards the reflection of the full environmental benefits or costs of each resource alternative" and indicated that it was consistent with earlier actions taken by U.S. utilities.

2.0 ELECTRICITY DEMAND FORECAST

General

The primary purpose of the demand forecast is to project future energy and peak demands to guide resource management and budget planning in the short-term and resource and transmission planning in the long term.

The forecast is based on research and analysis of economic and energy transaction data. Profiles of changing energy market conditions and business outlooks are developed to produce potential demand growth scenarios. Flexibility in meeting alternative demand growth scenarios provides a base for planning decisions and is an important criterion by which development options are judged.

The demand forecast is the sum of electricity required by the three major customer groups: Residential, Commercial and Industrial. For each customer group, the forecast is the product of two variables: projections of growth in number of accounts (units of stock) and electricity intensity per account (per unit of stock).

Projections of growth in number of accounts (units of stock) require forecasts of future population, Gross Domestic Product, demand for goods and services and industrial production that generate the need for electricity. For the long-term forecast, the major factors that determine electricity requirements are economic and demographic assumptions. Regional customer projections and major customer plans form the base of the short-term forecast.

Estimation of electricity intensity includes consideration of the impacts of technology, conservation, lifestyle and energy prices on electricity consumption. End-use forecasting techniques are used to analyze how customers presently use electricity and how consumption patterns are likely to change in the future. The effects of energy price changes are factored into the forecast by first establishing the scope customers have for changing their electricity use, and then estimating their reaction to price changes, based on historical trends.

Base Economic Forecast

Economic projections are based on input obtained from the Ministry of Finance and Corporate Relations and consultant studies for key industries.

The economy is expected to enter a period of moderate growth over the next five years with a projected average annual growth rate of 2.9%. A slower average growth rate of 2.5% is forecast for the first three years.

The provincial population is forecast to rise to 3 450 700 by 1995, an average growth rate of 2.1% per year. (It was 1.6% for the 1990's.) Net inter-provincial immigration is projected to average 26 100 per year, and net international immigration is expected to average 21 100 per year.

Base Electricity Forecast

A base projection, along with high and low scenarios (see below) were prepared as part of the short-term forecast in September, 1990.

Total gross generation requirements were projected to increase from approximately 45 610 GW·h in 1990/91 to 54 600 GW·h in 1995/96 for an annual average growth of 3.7% (includes Seattle City Light and West Kootenay Power commitments).

Peak demand for the integrated system was projected to increase from 8 225 MW in 1990/91 to 9 660 MW in 1995/96 for an annual average growth rate of 3.3% (including SCL and WKP commitments)

Alternative Demand Scenarios

Alternative scenarios of potential changes which could impact electricity sales were analyzed to produce the upper and lower bounds of uncertainty.

The low demand scenario emulated economic conditions of B.C.'s last major recession and the following recovery. Sales would be 3 900 GW·h lower than the base case by 1995/96 and the annual average growth rate would be 2.2% between 1990/91 and 1995/96.

The high demand scenario assumed B.C. will escape the worst of the economic downturn in the near term. Sales would be 2 500 GW·h higher than the base case by 1995/96, and the annual average growth rate would be 4.6% between 1990/91 and 1995/96.

Current Outlook

The outlook has changed since the forecast was prepared last September. All projections are being revised upwards. The base forecast is being increased by 500 - 600 GW·h/a for the years 1991 to 1994. The low demand scenario is now significantly closer to the base forecast, reflecting a less pessimistic view of the impact of the economic downturn on electricity sales. As a result, the band of uncertainty around the base forecast has been reduced considerably.

A new short-term electricity demand forecast is expected to be released this spring.

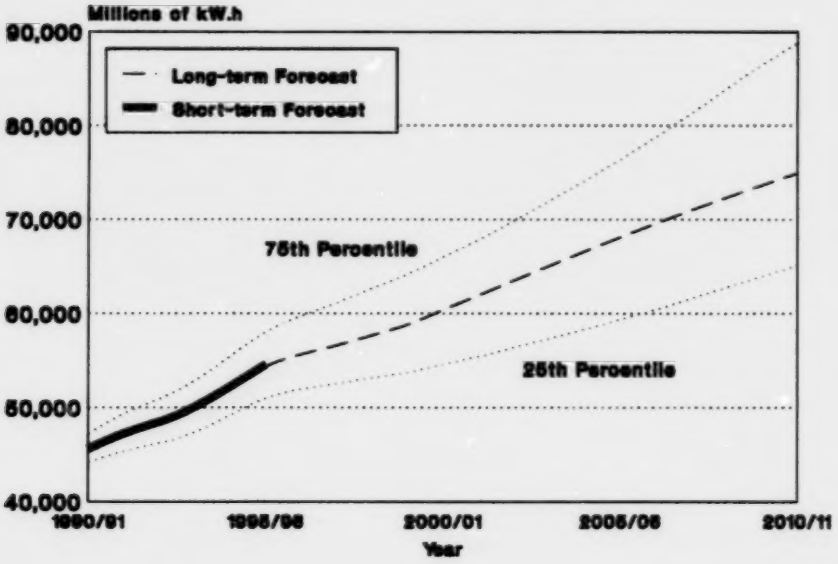
Long-term Forecast

As indicated in section 1.4, no change in long-term projections from the 1990 Electricity Plan has been assumed in this update. By 2010/11, gross requirements of about 75 000 GW·h and 13 600 MW are forecast.

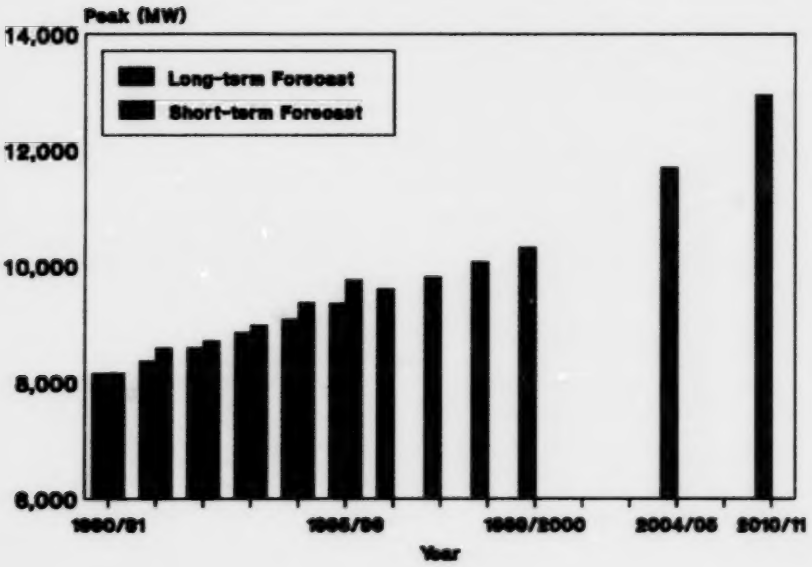
Exhibit 2-1 summarizes long-term forecast energy and peak demands, and presents the short-term forecasts for comparison.

Exhibit 2-1

ENERGY FORECASTS



PEAK FORECASTS



3.0 RESOURCE OPTIONS

3.1 POWER SMART

Efficient electricity end-use remains a dominant resource option to meet forecast demand growth. The Power Smart commitment has expanded since last year, from 4 300 GW·h/a by the year 2010, to 6 460 GW·h/a (adjusted for avoided transmission losses) and about 1 200 MW in peak reduction. B.C. Hydro's projected investment is also being increased, from $334 million to $600 million over the next 20 years.

Three main reasons are given in support of increasing Power Smart forecasts:

- early success of launched programs, which would be attributable to favourable customer response, climbing product sales, and adaptability of suppliers, manufacturers and contractors
- more information available about applied DSM
- a purposefully conservative estimate was originally assumed for Power Smart savings.

Nine programs were launched during the last year. They are:

Residential	Home Improvement
	Energy Education
Commercial	Building Improvements
	Energy Management Control Systems
	New Building Design
	Commercial Water Heating Conversion
Industrial	Efficient Fans
	Efficient Pumps
	Bonus Partners

Exhibit 3-1 provides information on the Power Smart program relative economics and projected load impacts by 2000. Exhibit 3-2 shows comparative Power Smart energy savings as estimated in 1989, 1990 and February 1991, for this update. It should be noted that resource planning studies utilize a range of potential Power Smart program impacts, currently estimated at between 70% and 110% of the figures reported below.

Estimated Power Smart program impacts are reviewed on an ongoing basis. The actual potential of the conservation resource can have significant implications on the timing and selection of other options. A Collaborative process with representation from industry, residential and commercial sectors, environmental groups, municipalities and West Kootenay Power was launched as a means to reach agreement on the size of this resource. Its conclusions are expected to be available in two phases, during 1991 and 1992.

Power Smart Inc.

B.C. Hydro announced the formation of Power Smart Incorporated, a wholly-owned subsidiary, in November 1990. Given Power Smart achievements and exposure, Power Smart Inc. will be able to provide a national energy efficiency focus with customers, governments, manufacturers, distributors, retailers and energy-related associations. The Power Smart name, logo, and programs may be used by utilities across Canada who join Power Smart, while qualifying products in both the U.S. and Canada will have access to the Power Smart name as a label.

Exhibit 3-1

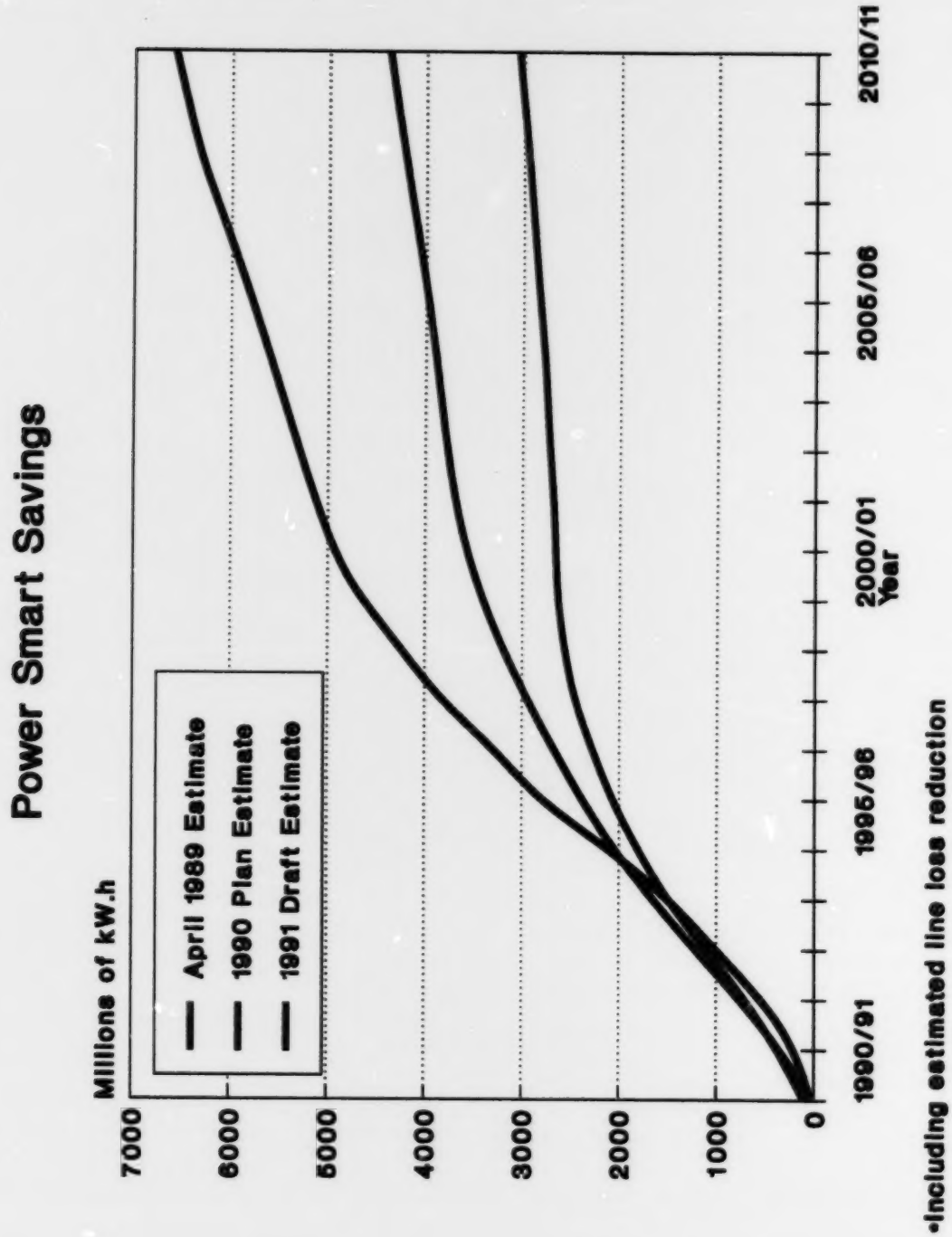
POWER SMART PROGRAM SUMMARY

POWER SMART PROGRAM	FOR THE YEAR 2000 ENERGY SAVINGS (GW·h)	PEAK REDUCTION (MW)	TOTAL RESOURCE UNIT COST* (¢/kW·h)
Residential			
Refrigerator Efficiency	169	33	0.8
Refrigerator Buy-Back	330	64	1.6
Power Smart Water Heaters	69	13	1.1
Electric To Gas Water Heaters	156	30	0.7
Water Heater Blankets	325	62	1.1
Home Improvements	323	62	4.6
Quality Plus Homes **	60	12	7.1
Non-Integrated Areas	34	7	5.4
Gas Fuel of Choice	243	47	1.0
Residential Total	1709	329	
Commercial			
Energy Efficient Lighting	812	156	2.2
New Building Design	302	58	2.8
Building Improvements	190	36	2.8
Energy Management Control Systems	10	2	4.1
Municipal Audits	18	3	2.3
Hydro In-House Efficiency	8	2	3.2
Commercial Total	1340	257	
Industrial			
High Efficiency Motors	368	60	1.3
Efficient Compressed Air	62	10	2.1
Energy Efficient Fans	55	9	3.4
Pumping Profits	74	12	2.5
Bonus Partners	200	33	1.4
New Plant Energy Assessment	42	7	0.8
Roadway Lighting - Ornamental	29	5	3.5
Roadway Lighting - Overhead	17	3	3.4
Industrial Total	847	139	
TOTAL POWER SMART	3896	725	
With Line Losses	4480	834	

* Excluding potential environmental credits of up to 15%

** Under review

Exhibit 3-2


Power Smart Savings
Millions of kW.h
7000
6000
5000
4000
3000
2000
1000
0
April 1989 Estimate
1990 Plan Estimate
1991 Draft Estimate
1990/91
1995/96
2000/01
2005/06
2010/11
Year
*Including estimated line loss reduction

3.2 IMPROVEMENTS TO EXISTING FACILITIES

Resource Smart

The Resource Smart program, which is intended to ensure most efficient use of B.C. Hydro's existing facilities, is projected to increase supply to the system by about 23 MW and 690 GW·h/a by 2000. Unit energy costs for these projects are typically in the 2 to 4 cents per kW·h range (1990 $), as shown in Exhibit 3-3.

Further Resource Smart gains of 1 000 MW and 3 000 GW·h/a are identified as economically competitive after 2000. This potential contribution would be comprised almost entirely of the five major Resource Smart projects which are part of the Lower Columbia Development: installation of power facilities at Keenleyside and Duncan dams, Seven Mile Unit 4, and additional generating facilities at Cominco's existing Waneta and Brilliant dams.

Deferral of commencement of the Lower Columbia Development until after 2000 in this Plan update provides an opportunity to reassess the development sequence for the Lower Columbia, in particular the five Resource Smart projects. Keenleyside was previously scheduled first because of the more advanced stage of its studies. However, it may now be desirable to bring forward some of the other projects which may be more economic, but whose studies are not as far advanced, notably the Waneta and Brilliant expansion projects. Feasibility investigations are scheduled to continue for Waneta in 1991/92 and to be initiated for Brilliant in 1992/93, including transmission requirements.

Waneta and Brilliant both appear to provide economic opportunities for expansion, to fully utilize the upstream flow regulating capability provided by dams which were built subsequent to these projects. In addition to their attractive long-term unit energy costs, Waneta and Brilliant would provide opportunities for increased operating flexibility and dependable capacity at existing upstream B.C. Hydro plants, Seven Mile on the Pend d'Oreille River and Kootenay Canal on the Kootenay River respectively, which are currently constrained by capacity limitations at the Cominco facilities.

Burrard Thermal

The potential contribution of the Burrard Thermal project has been increased to reflect purchase of competitively priced natural gas in the spot market. Burrard is capable of producing as much as 912 MW of capacity and 5 520 GW·h/a of energy, but since the early 1980's, plant capability has assumed no winter peak gas supplies. Only the energy capability on valley gas (gas that is generally available only during the summer months) was considered assured. This restricted plant capacity to 0 MW in the winter time with annual energy capability to 3 430 GW·h.

However, in recent years, a small firm gas contract has been required to utilize the plant to improve the voltage stability of the transmission system. In addition, the recent success in obtaining spot gas supplies is expected to continue. As a result, Burrard's capability for this Electricity Plan update has been increased to 40 MW of dependable capacity and 5 270 GW·h of energy. The low value for dependable capacity reflects the continued unavailability of spot gas supplies during the coldest days of the year. As a result Burrard's capacity is often derated at the same times when the demands on the B.C. Hydro system are greatest.

During the coming year, B.C. Hydro will be reviewing the actions necessary to achieving optimum system contribution from Burrard.

Exhibit 3-3

RESOURCE SMART PROJECTS (Partial List)

	Nominal Capacity Increase (MW)	Average Energy Gain (GW·h/a)	Unit Energy Cost* (¢/kW·h)
Projects Proposed			
Aberfeldie Expansion	15	60	5.3
Barnes Creek Diversion (Whatshan G.S.)	-	38	3.0
G.M. Shrum - Cooling Water	-	7	2.2
G.M. Shrum - Turbine Upgrade	-	78	2.9
John Hart - Penstock Painting	-	4	3.6
Kootenay Canal - Turbine Upgrade	-	110	2.8
Revelstoke - Turbine Tripods	-	14	0.6
Seven Mile - Turbine Upgrade	-	25	3.1
Shuswap - Rehabilitation	-	20	2.3
Lower Columbia Development			
Keenleyside Powerplant	240	980	7.0
Seven Mile Unit 4	185	280	3.0
Duncan Powerplant	25	105	8.9
Waneta Expansion	380	980	3.6
Brilliant Expansion	150	560	5.5

* Unit energy costs are preliminary estimates based on 1990 dollars, 8% net discount rate, excluding potential environmental credits of up to 15%.

3.3 COORDINATION AND MAJOR PURCHASES

Alcan

In addition to the energy and capacity covered under the current purchase and coordination agreements with B.C. Hydro, Alcan may have available up to 1 200 GW·h/a and 200 MW of electricity surplus to their existing or planned needs. In addition to various other possible uses, Alcan could sell this energy to other consumers, B.C. Hydro or to the Powerex Power Exchange Operation (PEO). No firm allowance for this surplus has been made in this update.

Most of the transmission lines and various modifications and enhancements required to connect this resource to the B.C. Hydro system and allow for coordinated operation and mutual emergency support are under construction.

Bonneville Power Administration (BPA)

The 750 GW·h/a of firm energy gained as a result of the 1990 Non-Treaty Storage Agreement is now considered part of B.C. Hydro's committed base system capability, in line with B.C. Hydro's traditional hydroelectric system criteria.

During 1990, BPA, Powerex, and B.C. Hydro also signed a new Interconnection and Exchange Agreement which outlines the basic principles governing current transactions between the two utilities. BPA and B.C. Hydro are now considering exploring opportunities for further coordinated operation which would use B.C. Hydro's reservoir storage on the Peace and Columbia River systems more effectively for mutual benefits. These discussions are at an early stage and will be contingent on the outcome of studies currently underway with Alberta on the Peace River system under the Transboundary Water Management Issues.

Alberta

Since completion of the second phase of coordination studies between B.C. Hydro and TransAlta in 1989, negotiations for coordinated operation, reserve sharing and emergency support have developed detailed principles which are expected to be signed by the parties in March, 1991. Coordinated operation is presently taking place on a monthly basis through letters of agreement.

It was estimated that ad hoc arrangements were capturing about 50% of the potential benefits and that formal agreements should capture an additional 30%. The remaining 20% could only be captured by a totally integrated, one system dispatch.

Since the studies were completed, both corporations have modified their resource plans thereby reducing the potential benefits available from coordination. (TransAlta has shifted their coal/gas mix, i.e. reducing surplus off peak coal energy in the longer term. B.C. Hydro now plans to rely more heavily on cogeneration, conservation and coordination with other parties, which reduces surplus capacity, but increases energy availability.)

Although an exchange agreement was a component of early negotiations, the above changes have reduced B.C. Hydro's interest in long-term purchase of Alberta energy. However, TransAlta remains interested in the purchase of capacity from B.C. Hydro and transmission access to U.S. markets. These two elements are the focus of ongoing negotiations.

3.4 PRIVATE POWER GENERATION

The provincial government and B.C. Hydro are encouraging the development of private sources of electricity through customer self-generation and purchases from independent power producers (IPPs). It is anticipated that private power production achieved through a competitive market will lower the cost of electricity in B.C.

Since the publication of the 1990 Electricity Plan, B.C. Hydro has:

- Established key principles with Vancouver General Hospital for a 13.5 MW natural gas self-generation project. Proposals for a total of 330 MW have been received to date under the self-generation program, and an additional 200+ MW is under study by potential proponents.

- Received fourteen proposals, and signed electricity purchase agreements for nine hydro projects under the Small IPP program (less than 5 MW). They range in nameplate capacity from 62 kW to 10 MW, and will collectively contribute 41 MW and 192 GW·h/a.

- Established key principles with Northern Utilities for a 50 MW (250 GW·h/a) hydro project on the Mamquam River near Squamish.

B.C. Hydro presently projects that by the end of the decade, approximately 5 200 GW·h/a of new electricity will be generated annually in B.C. by self-generation and IPPs collectively. These projects are smaller, require less lead time, and can be developed closer to demands than large hydroelectric projects, and thus can help to efficiently maintain B.C.'s demand/supply balance.

The majority of the projected electricity is expected to come from self-generation due to the economies associated with the cogeneration of electricity with steam and the coincident disposal of wood waste.

Exhibit 3-4 summarizes currently projected contribution from private sector projects.

The provincial government has also expressed support for a gas-fired generating station on Vancouver Island. The plant would utilize a portion of the natural gas provided by the 537 km pipeline currently under construction, provide incremental revenue benefits to the province and help recover public investment in the pipeline. It would also defer the need for additional transmission to Vancouver Island in the early 2000's.

No allowance has been made in this update for the potential additional contribution from this station (estimated to be about 200 MW). A detailed evaluation of this project has not yet been completed.

Exhibit 3-4

PRIVATE POWER PROJECTIONS

	Self Gen. Note 1		Large IPPs Note 2		Small IPPs		Total	
	Energy (GW.h)	Capacity (MW)	Energy (GW.h)	Capacity (MW)	Energy (GW.h)	Capacity (MW)	Energy (GW.h)	Capacity (MW)
92/93	0	0	0	0	67	15	67	15
93/94	220	30	875	160	68	15	1163	205
94/95	800	110	1530	210	192	41	2522	361
95/96	1700	230	1530	210	192	41	3422	481
96/97	2600	350	1530	210	192	41	4322	601
97/98+	3500	470	1530	210	192	41	5222	721

Note 1: Excluding Howe Sound Pulp and Paper

Note 2: Consists of Northern Utilities, NW Energy and Westcoast projects.

3.5 COLUMBIA RIVER TREATY DOWNSTREAM BENEFITS

As part of the provincial energy policy, the government has announced that the Downstream Benefits will be returned to British Columbia. The government will determine how this resource can best be used to benefit British Columbia.

Since the 1990 Electricity Plan was published, discussions on the return of the DSBs have continued between the U.S. and Canadian Entities, which are jointly responsible for implementation of the Treaty. Resource plans currently being prepared by PNW utilities and planning agencies reflect the return of the Canadian Entitlement to B.C.. However, the allocation of the obligations amongst those utilities having to provide the Canadian Entitlement has not been determined and is likely to prove complex and difficult. The return of the DSBs raises four key considerations for B.C. Hydro:

Energy

There is reasonably good agreement with the U.S. Entity on the methodology and hence the amount of energy that the U.S. would be required to return under various possible U.S. Pacific Northwest (PNW) supply-demand outcomes. The magnitude of the DSBs depends on the rate of demand growth in the PNW and the amount of thermal and hydroelectric generation used to serve that demand. As electricity demand in the PNW increases, U.S. utilities will likely have to add more thermal resources to serve their requirements and the value of the streamflow regulation in the U.S. resulting from the Canadian Treaty dams, decreases. Hence the higher the PNW demand growth the lower the DSBs and vice versa. Furthermore, this sensitivity is very substantial. On the basis of previous studies, the energy component of the DSBs would double if the PNW experienced low demand growth as opposed to high growth.

Capacity

The capacity credit component of the DSBs is not sensitive to the demand growth in the PNW. Previous studies completed by B.C. Hydro have indicated that the capacity credit would be about 1 100 MW after full return of the DSBs. There is agreement between the U.S. and Canadian Entities on most aspects of how the capacity credit portion of the DSBs is to be calculated, but discussions are continuing on computation of the limitation applicable to the capacity credits.

Since the capacity credit represents a very sizeable resource to B.C. Hydro, the current uncertainty, together with other considerations identified below, make it difficult to develop transmission plans for the B.C. Hydro system. Depending on the amount of the capacity credit, the delivery point, and the disposition of the DSBs within B.C., transmission requirements could be affected significantly. Since capacity considerations, particularly to serve the Lower Mainland, have become much more critical, the uncertainties and unresolved issues relating to the DSBs have become pertinent.

Delivery Point

At the time the Columbia River Treaty and the original 30-year sale of the Canadian Entitlement to the DSBs were negotiated, it was difficult for negotiators to predict how the regions and their utility systems would develop over the following decades. The Treaty specified that the Canadian Entitlement be delivered to B.C. at Oliver, a location in the vicinity of the border approximately in the middle of the province.

Although Oliver is stated as the delivery point in the agreement, BPA and B.C. are free to agree on an alternative. Studies are currently underway to assess the cost to develop transmission for several options. For the purpose of such transmission planning studies, B.C. Hydro has assumed that half of

the DSBs would be returned at Ingledow substation in Surrey and half at Nelway substation south of Salmo.

Disposition

Since the DSBs belong to the province of B.C., the government must decide how to use or allocate this resource. Over the past several years, in planning studies which included return of the DSBs, B.C. Hydro had assumed that the DSBs would either be directly supplied to B.C. Hydro to be used to serve B.C. Hydro loads, or supplied (in whole or in part) to various industries or groups of electricity consumers that would otherwise be served by B.C. Hydro. The net effect on B.C. Hydro would be the same for either outcome.

Since it is possible that the DSBs (in whole or in part) could be used to serve demands not presently included in B.C. Hydro's demand forecast, current planning studies consider a range of possible outcomes in this regard. The "reference case" assumption is that the DSBs will be available to serve demands on the B.C. Hydro system or to serve demands that would otherwise be served by B.C. Hydro. Alternative scenarios are considered where it is assumed that the full amount or a portion of the DSBs may be used for other customers.

3.6 NEW HYDROELECTRIC DEVELOPMENT

Following a decision in early 1991 to defer the Peace Site C project, engineering and environmental studies are currently being wound down and documented to facilitate reactivation of the project when required. To maintain Site C as a contingency option for future supply, a limited amount of basic data collection and consultation with regulatory agencies and the public will continue in 1991/92. The project would increase supply to the system by 900 MW and 4 710 GW·h/a.

Investigations for the Lower Columbia Development have also been curtailed. The Lower Columbia Development includes the Murphy Creek and Border projects on the Columbia River mainstem, in addition to five Resource Smart projects. Murphy Creek would increase supply by 275 MW and 1 490 GW·h/a and Border, 250 MW and 1 510 GW·h/a respectively. Unlike the Resource Smart projects, which would involve utilization or expansion of existing facilities, the Murphy Creek and Border projects would require construction of new dams. The higher unit energy costs and environmental impacts of these projects relative to the Lower Columbia Resource Smart projects suggest that Murphy Creek and Border will continue to be considered for the later stages of the Lower Columbia Development sequence.

3.7 THERMAL AND ALTERNATIVE ENERGY

Thermal

Thermal power generation may use waste products (wood waste, municipal solid waste (MSW), landfill gas, sewer sludge or coal waste), thermal coal, fuel oil, natural gas or uranium. There are many mature and developing technologies to utilize these resources for electricity generation. Natural gas is currently the fuel of choice for thermal power generation among IPPs, but future natural gas prices are uncertain. The use of waste products for power generation is inhibited because of insecure supplies as new uses are discovered and because of the dispersed nature of most supplies. However, it is expected that restrictions on the disposal of all waste products, including wood, will encourage their use for by-product power generation among self generators and IPPs.

Thermal power generation technologies such as fluidized bed, gasification and others have improved energy conversion efficiencies decreased costs and reduced emissions. Breakthroughs are not expected in the near

term. However, gradual improvements are expected to continue with efficiencies reaching 45 percent for natural gas-fired thermal power generation and more than 85 percent with cogeneration.

There are few diesel generating sets on the B.C. Hydro system and there is a continuing trend to reduce the number by developing alternate generation from independent power producers (IPPs). However, some local niches may develop for natural gas-fired diesel or diesel/steam (combined cycle) cogeneration facilities in the future as technology improves.

Alternative and Emerging Technologies

- **Small hydro** development is being successfully pursued in B.C. by the private sector under the small IPP program. New invitations for proposals are being deferred at the government's request, to allow time to streamline the review and approval process, in view of the large number of projects anticipated.

- Extensive investigations are being carried out for **geothermal** energy at Meager Creek, where private interest for development exists.

- **Solar** photovoltaic electricity generation is expected to be competitive as a small scale alternative to conventional utility generation in the U.S. by the late 90s. However, generation from photovoltaics at the best site in B.C. yields approximately 2/3 of the energy from the same system at Albuquerque, New Mexico.

- **Wind** generation is a proven technology with more than 2 000 MW installed world-wide. Although uneconomic for on-grid generation in B.C., wind generation technology is still evolving rapidly and unit energy costs are decreasing because of improved materials, control equipment and siting.

- The use of **tidal** power has been slow to develop because of high costs and nvironmental impacts, but major installations exist in France and Nova Scotia. A few sites have been evaluated on the B.C. coast.

- **Wave** conversion devices are still at an early stage of development, particularly those which would be developed offshore where wave energy is highest. Prototypes of onshore wave conversion devices have been developed with capacities as large as 500 kW.

- The use of **hydrogen** as an energy carrier with its high energy density is stimulating a great deal of interest in B.C. and elsewhere. Hydrogen from electrolysis provides an efficient method of transporting electrical energy over long distances in a buried pipeline to eliminate the visual impact of transmission lines.

- Hydrogen can be used to generate electricity in **fuel cells** without producing harmful emissions. Recent developments in fuel cell technology are being scrutinized by B.C. Hydro, Powertech Labs (a research subsidiary of B.C. Hydro), and the provincial government.

B.C. Hydro will continue to monitor developments in alternative energy technologies and may be involved in the demonstration of promising technologies. With the exception of small hydro, alternative energy projects are not included in this Electricity Plan because of uncertainties regarding cost and/or availability, but they may be factored in future plans.

Exhibit 3-5 provides some typical costs for thermal and alternative energy projects.

Exhibit 3-5

THERMAL AND ALTERNATIVE ENERGY COSTS

	Project Size (MW)	Energy Cost* (¢/kW·h)
solar photovoltaic	100	23
tidal	660	30
small hydro	<5	3 - 4
wind	16	14-24
geothermal	55	7
wood waste thermal	25	9
cogeneration (wood/MSW)	25-45	6
fuel cell	.2	11-21
gas turbine	25	6
gas turbine/combined cycle	35	5
coal-fired:		
conventional	2000	5
waste coal	600	7
advanced technologies	400-1000	6
nuclear	400	6

* Includes preliminary estimates of the cost of transmission to the Lower Mainland.

4.0 DEVELOPMENT STRATEGY

4.1 SHORT-TERM OUTLOOK

Twelve month sales to February 1991 were 5.0% higher than for the same period the previous year. Actual demands exceeded forecasts for all sectors. However, some softening is becoming apparent in sales in several areas.

Demand

Total gross energy requirements (including firm commitments to Seattle City Light and West Kootenay Power Ltd.) for fiscal year 1990/91 are expected to be 45 610 GW·h with a peak demand of 8 225 MW (actual new record set December 1990). Over the next five years these requirements are expected to grow at a rate of about 3.7% per year, and at about 2.3% thereafter.

Supply

B.C. Hydro is anticipating favourable streamflow conditions for the balance of this operating year (until September 1991). As of 1 March 1991, the run-off into the G.M. Shrum and Mica projects was forecast to be 112% and 114% of average, respectively. For the system as a whole, anticipated run-off is about 115% of average. As a result of these projected high run-off conditions, major system reservoirs are expected to refill to within about five feet from full by September 1991.

The annual firm energy capability of the hydro system is now 43 600 GW·h/a including BPA coordination and Resource Smart gains to the end of fiscal 1990/91. The dependable peak capacity is 9 293 MW. In some water conditions the hydro system can produce more energy (a total of 46 700 GW·h/a under average water conditions). If required, Burrard Thermal and existing gas turbines can contribute up to 5 820 GW·h/a of firm energy and 180 MW of dependable capacity. This assumes that about 1 800 GW·h/a could be made available at Burrard Thermal through purchases of natural gas on the spot market. Also, Burrard contributes only 40 MW toward dependable capacity because spot gas surpluses are not assured during the coldest days of the year. Additional non-firm energy may be available from Alcan, Alberta, or U.S. utilities.

In addition to existing B.C. Hydro facilities and judicious use of non-firm supplies, demand growth through the mid 1990's will be met through committed and budgeted resources such as ongoing Power Smart and Resource Smart initiatives; purchases of about 250 MW and 1 700 GW·h/a from signed IPPs; purchases and coordination with Alcan providing 300 MW (maximum 590 MW) and 2 770 GW·h/a; further demand reductions of about 470 MW and 3 500 GW·h/a from self-generation; and reserve sharing with Alberta providing back up support equivalent to 400 MW.

4.2 LONG-TERM STRATEGY

Section 3 provided a description of the various options available to meet forecast demands in excess of the capability of existing and committed resources.

Selection of some of these projects for the Electricity Plan is done on the basis of minimizing total long-term costs of acquisition and operation. Cost-effectiveness, however, is not the only criterion. Each option has different characteristics and implications. Therefore, they are all evaluated with respect to other criteria such as availability, public acceptability, socio-economic and environmental impacts, uncertainty and transmission impacts.

In its 1990 Electricity Plan, B.C. Hydro established a resource development priority

which reflected a preliminary weighting of the attributes listed above. This update reflects the same priority:

1. Power Smart
2. Coordination and Purchases
3. Resource Smart
4. Private Sector Generation, Self-generation and Load Displacement
5. New hydro generation in developed river basins and
6. New hydro generation in undeveloped river basins.

Studies conducted to evaluate alternative combinations of resources showed that the current outlook for the quantity and price of resources available in the first four categories (plus the return of the Canadian Entitlement of the Columbia River Downstream Benefits) is such that no major new hydro generation facilities in either developed or undeveloped basins need be scheduled at this time. Such facilities may be needed within the 15-year period to 2005 only if actual demand growth is substantially higher than currently projected, or other options do not materialize.

Therefore, during the late 1990's electricity requirements are planned to be met by expansion of the Power Smart and self-generation initiatives, and the assumed return of the DSBs. After the year 2000, this Plan proposes to add Seven Mile Unit 4 and expand Waneta and Brilliant facilities, between 2005 and 2008 for a total increase in supply of 715 MW and 1 820 GW·h/a (average). About 1 700 MW of capacity and 11 000 GW·h/a of additional energy would be required to the end of the 20-year period, at this point assumed to come from projects which could be undertaken by either B.C. Hydro or IPP proponents. The bulk of this new capacity would be required to replace Burrard Thermal, which is expected to be retired from service by the end of the 20 year period.

Exhibits 4-1 through 4-4 provide a detailed breakdown of how B.C.Hydro plans to meet energy and capacity requirements over the next 20 years. In the past, energy considerations have tended to dominate scheduling of new resources. However, B.C. Hydro's increased reliance on coordination, various non-firm energy sources and other sources of supply contributing primarily energy (but little or no capacity), combined with the minimization of construction of new facilities, has resulted in much more closely matched balance between capacity demands and supplies.

Note that demand/supply imbalances shown in Exhibits 4-1 and 4-4 for the 25th and 75th percentile demands tend to overstate such imbalances, because Resource Development Plans will be adjusted if higher or lower growth trends are detected.

Capacity Considerations

The B.C. Hydro electric system is planned to meet the expected peak demands which occur during winter months (December to February). Consequently, the timing and the dependability of the capacity of a generating unit is vital. The **dependable capacity** rating measures the amount of power that a unit can reliably deliver during peak periods (about 1-3 hours per day).

Capacity losses associated with reservoir drawdown and current hydro operating procedures, which emphasize reducing spill and maximizing system energy output limit the hydro dependable capacity to 8 897 MW. Modifying operating practices at a small increased cost would be considered prior to making additional investments in capacity. The new practice would allow controlled spill to enable plants to run at full capacity when additional capacity is required during the unusually high load demand periods. This practice would also allow small Lower Mainland and Vancouver Island reservoirs to be kept at higher levels, which might increase the risk of spilling. These revised operating procedures would increase hydro dependable capacity to 9 293 MW. The cost due to

potential loss of energy ranges from $.75/kW/a to $19/kW/a.

The unavailability of economic firm gas supply during the winter peak period reduces Burrard dependable capacity to 40 MW. With fuel supply arranged for Keogh and Prince Rupert gas turbines, dependable capacities could be maintained at 94 MW and 46 MW respectively.

Business principles of an agreement between the Alberta Integrated System and B. C. Hydro on Reserve Sharing and emergency support are expected to be signed by the parties in March 1991. Support from Alberta would allow B.C. Hydro to reduce its reserve requirements by 400 MW.

With the modified operating practices, and assuming the reserve sharing agreement with Alberta is in place, the peak load carrying capability of the existing system is about 8 900 MW. This represents the largest peak demand the system can reliably serve after allowing for forced outages of generation and related equipment.

In the near term, IPP projects as well as the coordinated operation and purchase from Alcan could provide up to 840 MW of dependable capacity. The return of Columbia River Treaty downstream benefits, additional IPP projects, as well as the development of Seven Mile Unit 4 and expansion of Waneta and Brilliant facilities between the late 1990's and 2010, should provide another 3 600 MW of dependable capacity.

A potential, economic source of additional capacity in the system would involve installation of units 5 and 6 at Revelstoke and/or Mica, thus completing the work authorized for these projects under the terms of the Water Licences. Addition of two units could add 900 MW and 800 MW dependable capacity at Revelstoke and Mica respectively. Preliminary studies indicate an average unit capacity cost from the projects of about $56/kW/a (1990 $), including integration into the provincial grid and system reinforcement into the Lower Mainland.

Capacity Definitions

The capacity of a generating unit can be measured in several ways. The most common is the unit's nameplate capacity. Another commonly used rating is the maximum continuous capacity which is the highest amount of power the unit can produce on a continuous basis, given favourable operating conditions. The total nameplate capacity of all existing hydro and thermal units is 9 331 MW and 1 058 MW respectively while the total maximum continuous capacity of all existing hydro and thermal units is 9 980 MW and 1 060 MW respectively. However, the generating capacity may vary on a seasonal basis and can be limited by a combination of the following factors:

- continuous overload ratings on turbines, generators and related equipment,
- expected hydraulic head and the turbine's capacity versus head rating,
- expected flow and operating constraints,
- limitation due to fuel supply, including availability of water, and
- ambient temperature considerations for thermal units

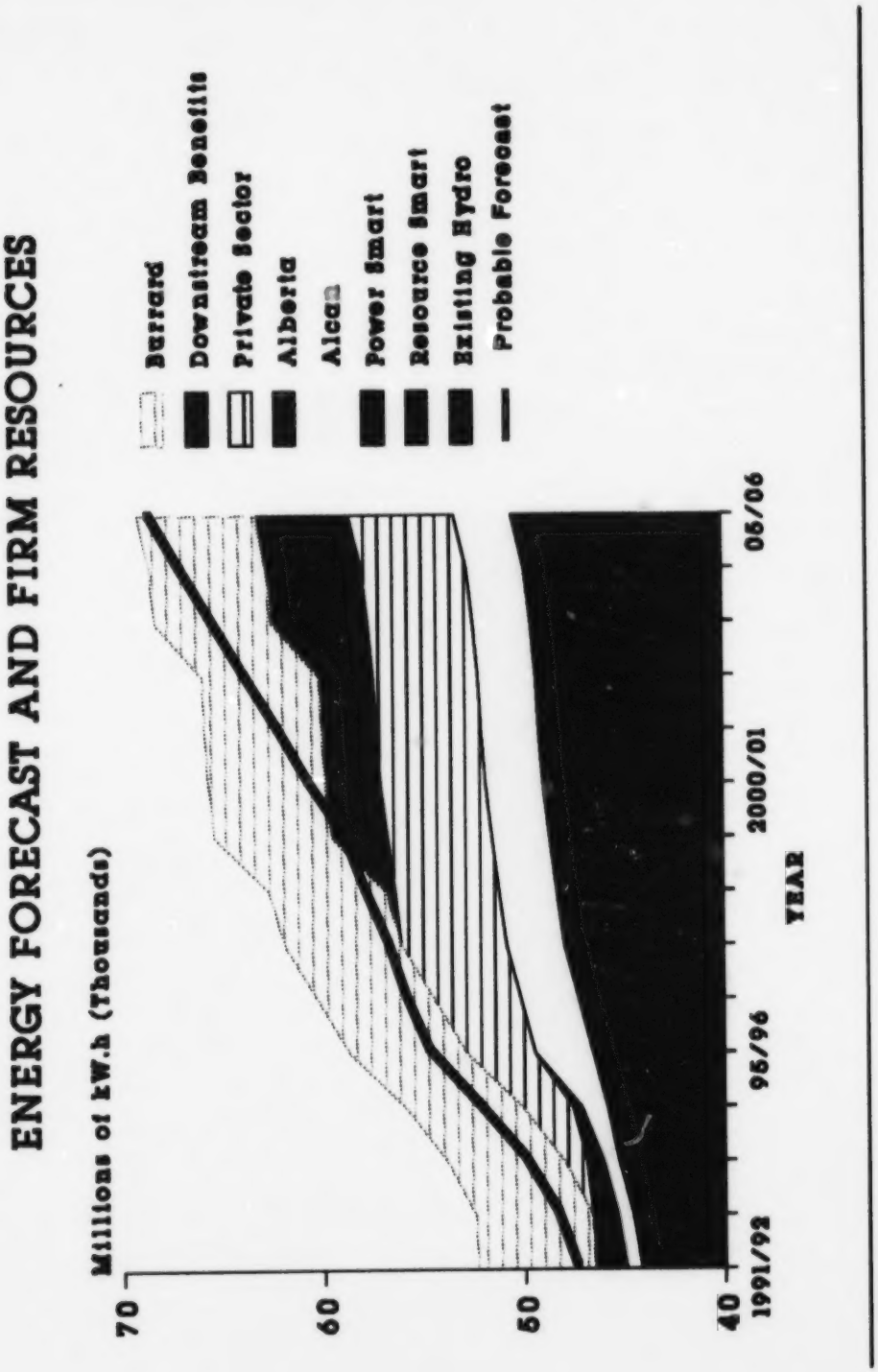
FORECAST ENERGY DEMAND AND FIRM SUPPLY
Millions of kW.h

	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	05/06	10/11
PROBABLE DEMAND	**47420**	**48370**	**49940**	**52200**	**54580**	**55700**	**56570**	**57700**	**58710**	**60420**	**68130**	**74970**
Power Smart	510	930	1430	1990	2580	3210	3710	4110	4480	4850	5890	6540
Self-generation	0	0	225	820	1710	2610	3500	3500	3500	3500	3500	3500
NET PROBABLE	**46910**	**47440**	**48285**	**49390**	**50290**	**49880**	**49360**	**50090**	**50730**	**52070**	**58740**	**64930**
FIRM SUPPLY												
Existing Hydro	43520	43520	43520	43520	43520	43520	43520	43520	43520	43520	43520	43520
Burrard	5270	5270	5270	5270	5270	5270	5270	5270	5270	5270	5270	0
Gas Turbines	550	550	550	550	550	550	550	550	550	550	550	550
Resource Smart	160	200	340	370	470	540	630	690	690	690	690	690
Alberta Purchases	1600	1200	800	400	0	0	0	0	0	0	0	0
Alcan Purchase & Coordination	665	665	665	1195	2770	2770	2770	2770	2770	2770	2770	2770
Signed IPP's	5	65	940	1740	1720	1720	1740	1670	1710	1740	1710	1740
Return of DSB's	0	0	0	0	0	0	0	480	2790	2760	4710	4510
New Resources	0	0	0	0	0	0	0	0	0	0	160	11520
TOTAL FIRM SUPPLY	**51770**	**51470**	**52085**	**53045**	**54300**	**54370**	**54480**	**54950**	**57300**	**57300**	**59380**	**65300**
SUPPLY/DEMAND BALANCE												
25th PERCENTILE *	6680	6110	6265	6355	6960	7640	8540	8710	11370	10690	9500	10380
PROBABLE	**4860**	**4030**	**3800**	**3655**	**4010**	**4490**	**5120**	**4860**	**6570**	**5230**	**640**	**370**
75th PERCENTILE *	2720	1700	1065	525	470	590	790	−30	1040	−570	−8230	−14150

* NOTE : These values overstate differences between supply and demand because the Resource Development Plan will be adjusted in response to higher or lower growth trends as they are detected.

Exhibit 4-1

Exhibit 4-2


ENERGY FORECAST AND FIRM RESOURCES
Millions of kW.h (Thousands)
70
60
50
40
1991/92
95/96
2000/01
06/06
YEAR
Burrard
Downstream Benefits
Private Sector
Alberta
Alcan
Power Smart
Resource Smart
Existing Hydro
Probable Forecast

FORECAST ENERGY DEMAND AND EXPECTED RESOURCE USE
Millions of kW.h

	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	05/06	10/11
GROSS EXPECTED DEMAND	**47270**	**48160**	**49660**	**51980**	**54410**	**55540**	**56410**	**57520**	**58530**	**60250**	**67940**	**74800**
Power Smart + Res. Smart Loss Red.	600	1140	1550	2100	2650	3330	3780	4120	4500	4840	5410	6450
Self-generation	0	0	235	810	1720	2600	3500	3500	3500	3500	3500	3500
NET EXPECTED DEMAND	**46670**	**47020**	**47875**	**49070**	**50040**	**49610**	**49130**	**49900**	**50530**	**51910**	**59030**	**64850**
Domestic Load Not Served	0	0	0	0	0	0	0	0	0	10	440	530
EXPECTED RESOURCE USE												
Total Hydro	47100	47150	47260	47370	47830	47830	47890	47960	47700	47860	48300	48940
Burrard	2500	3140	3100	3010	2970	2870	2730	2770	2360	2670	3580	0
Gas Turbines	0	0	0	0	0	0	0	0	0	10	90	90
Alberta Purchases	90	150	170	190	150	130	100	120	70	150	570	510
Alcan Purchase & Coordination	180	200	210	950	2710	2700	2690	2690	2720	2750	2830	2780
Signed IPP's	0	100	900	1700	1700	1700	1700	1700	1700	1700	1700	1700
Downstream Benefits	0	0	0	0	0	0	0	490	2820	2790	4800	4520
New Resources	0	0	0	0	0	0	0	0	0	0	0	10500
TOTAL EXPECTED RESOURCE USE	**49870**	**50740**	**51640**	**53220**	**55360**	**55230**	**55110**	**55730**	**57370**	**57930**	**61870**	**69040**
NON-FIRM MARKETS SERVED												
Domestic Interruptible Mkt.	390	400	370	360	370	370	380	370	390	370	250	290
Alberta Interruptible Mkt.	0	10	10	20	20	20	30	30	50	30	10	60
U.S. Export Markets	2790	3310	3390	3800	4980	5250	5590	5460	6410	5650	3350	4720
TOTAL NON-FIRM MARKETS SERVED	**3180**	**3720**	**3770**	**4180**	**5370**	**5640**	**6000**	**5860**	**6850**	**6050**	**3610**	**5070**

FORECAST PEAK DEMAND AND CAPACITY SUPPLY
Megawatts

	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	05/06	10/11
PROBABLE DEMAND *	**8590**	**8710**	**8980**	**9370**	**9760**	**10010**	**10260**	**10520**	**10760**	**11060**	**12380**	**13630**
Power Smart	100	170	270	370	480	600	690	760	830	900	1060	1210
Self – Generation	0	0	30	110	230	350	470	470	470	470	470	470
NET PROBABLE	**8490**	**8540**	**8680**	**8890**	**9050**	**9060**	**9100**	**9290**	**9460**	**9690**	**10850**	**11950**
DEPENDABLE CAPACITY												
Existing Hydro	9293	9293	9293	9293	9293	9293	9293	9293	9293	9293	9293	9293
Burrard	40	40	40	40	40	40	40	40	40	40	40	0
Gas Turbines	140	140	140	140	140	140	140	140	140	140	140	140
Resource Smart	0	0	0	0	15	15	23	23	23	23	395	735
Alcan – Maximum Transfer	76	76	76	76	590	590	590	590	590	590	590	590
Signed IPP's	2	15	225	251	251	251	251	251	251	251	251	251
Return of DSBs	0	0	0	0	0	0	0	100	600	600	1100	1100
New Resources	0	0	0	0	0	0	0	0	0	0	0	1750
TOTAL DEPENDABLE CAPACITY	**9551**	**9564**	**9774**	**9800**	**10329**	**10329**	**10337**	**10437**	**10937**	**10937**	**11809**	**13859**
PEAK LOAD CARRYING CAPABILITY **	**8900**	**8910**	**9040**	**9140**	**9610**	**9610**	**9610**	**9710**	**10170**	**10170**	**10980**	**12890**
BCH Required Reserve	651	654	734	660	719	719	727	727	767	767	829	969
AIS Reserve Sharing	400	400	400	400	400	400	400	400	400	400	400	400
Total Required Reserve (MW)	1051	1054	1134	1060	1119	1119	1127	1127	1167	1167	1229	1369
– % of Dep. Capacity	11.0	11.0	11.6	10.8	10.8	10.8	10.9	10.8	10.7	10.7	10.4	9.9
BCH Required Reserve (% of FPLCC)	7.3	7.3	8.1	7.2	7.5	7.5	7.6	7.5	7.5	7.5	7.6	7.5
SUPPLY/DEMAND BALANCE												
25th PERCENTILE ***	790	820	840	800	1150	1180	1230	1240	1640	1530	1560	2520
PROBABLE	**410**	**370**	**360**	**250**	**560**	**550**	**510**	**420**	**710**	**480**	**130**	**940**
75th PERCENTILE ***	0	−120	−210	−380	−150	−250	−290	−450	−190	−470	−1440	−1810

NOTES:

* The Probable Demand incorporates revisions to estimated WKP&L requirements, and increases of about 100 MW to reflect the maximum expected SCL requirement under the Skagit Valley Treaty.

** Peak Load Carrying Capability is derived from the Total Dependable Capacity by a detailed reliability analysis.

*** These values overstate differences between supply and demand because the Resource Development Plan will be adjusted in response to higher or lower growth trends as they are detected.

4.3 ALTERNATIVE SCENARIOS

Several alternative resource sequences were investigated during the preparation of this Electricity Plan update.

(i) Depending on market conditions and the relative performance of other resource initiatives, it may be attractive to advance scheduling of some projects on the Lower Columbia basin, in particular Seven Mile Unit 4 and the Waneta expansion. Both offer economic capacity and energy, well below currently projected avoided costs for the late 1990's and early 2000's.

An early agreement with Cominco Ltd. on additions to Waneta and Brilliant stations should be pursued for possible in-service by the turn of the century.

(ii) The Peace Site C project could be advanced to support government initiatives towards economic development. An in-service date in the early 2000's would be feasible given the project's advanced (shelf-ready) status. Strong domestic demand growth or underperformance by other resources could also bring about an advancement in the in-service date for this project.

(iii) Unavailability of the downstream benefits was found to have a significant impact on scheduling of new resources. Section 6 (Risk Management) addresses this possibility, under resource uncertainty.

4.4 ELECTRICITY TRADE

Powerex Power Exchange Operation

As evidenced in the Exhibits 4-3 and 4-4, there could be in order of 250-500 MW and 3 000 - 6 000 GW·h/a of energy in excess of domestic demand under average water conditions. This surplus capability of hydro storage, generation and transmission will be used to maximize the return on B.C. Hydro facilities through short-term sales.

Powerex, a wholly-owned subsidiary of B.C. Hydro, administers and coordinates short-term electricity sales through a 'power exchange' within B.C. and with Alberta and the U.S. B.C. Hydro's surplus capability supports the Powerex Power Exchange Operation (PEO). The PEO provides utility and non-utility electricity suppliers and electricity consumers access to a market-priced short-term energy exchange. The unbundled energy services such as storage, generation, wheeling, and backup will be exchanged at prices which provide the greatest gain to the PEO. These benefits will be returned to B.C. Hydro in exchange for the use of its system.

Wheeling

In attempting to optimize benefits to B.C. Hydro and its customers from the efficient management of electric system resources, 'unbundling' the electric utility service into its components and determining their costs may be required. Through pricing signals, as to time and location of product/service availability, it is possible to achieve the market conditions which offer the best return to B.C. Hydro and other participants on the integrated system.

Transmission wheeling can provide services such as load shaping, storage, backup and increased reliability. Wheeling is more than moving electricity from one system to another through a third party, when considered from an energy services marketing perspective. Each of the wheeling components is marketed to optimize B.C. Hydro's financial return. Pricing provides the signals to energy service consumers as to B.C. Hydro's preferred time and location for making the service available.

Currently, B.C. Hydro negotiates long-term wheeling contracts with clients. Short-term arrangements are coordinated by the PEO.

5.0 TRANSMISSION DEVELOPMENT STRATEGY

The overall objective of the transmission development strategy is to shape tomorrow's electric system to assure customers of a reliable, efficient supply of electricity while minimizing effects on the environment.

Exhibit 5-1 is a map of B.C. Hydro's major electrical system which shows both existing and proposed generation and transmission facilities. The development of the major transmission system is influenced by the location and magnitude of new generation resources, coordination and purchase agreements, and by regional changes in the demand for electricity. Exhibit 5-2 shows the present imbalance between each region's installed generation capability and its corresponding electricity demand.

Improvements to the Existing System

The Interior to Lower Mainland transmission system is presently operating near its capacity. Completion of the American Creek Series Capacitor Station north of Hope provided the most recent incremental increase in system capacity. Upgrading the thermal capacity of the existing 500 kV Peace transmission lines from Hudson's Hope into the Lower Mainland continues and is expected to be completed in 1992.

The Interior to Lower Mainland transmission system has become limited by voltage stability considerations. Voltage control equipment planned for installation in existing substations over the next few years as well as additional transmission line construction from Kelly Lake and Nicola substations into the Lower Mainland. The option of curtailing load in the Lower Mainland and on Vancouver Island starting in about 1995 is also being investigated. Some flexibility is retained by allowing this mix of options to be rescheduled to respond to changing demand growth patterns, delays in major project approvals and other uncertainties.

Impact of IPPs, Cogenerators and Wheeling

The location, size and operation of independent power producers and cogenerators determines their impact on the transmission system. Electricity produced at an Interior location would result in additional loading of the transmission system supplying the Lower Mainland and Vancouver Island, whereas an IPP or a cogenerator located in the Lower Mainland or on Vancouver Island would help to offload the transmission system. When known, the location of potential IPPs and cogenerators is taken into account in planning for transmission reinforcements.

In 1990, B.C. Hydro provided the B.C. Utilities Commission with a proposal to allow wheeling on the B.C. Hydro system, for a fee. The wheeling fees are intended to recover the costs of any new transmission required and to ensure there is no impact on B.C. Hydro's domestic customers.

Integrating New Generation Projects

B.C. Hydro will continue to study the transmission options for Lower Columbia generation projects. A 230 kV transmission system would likely be used to connect them to the major electrical system through Selkirk Substation east of Trail.

Corridor Planning

Future availability of transmission corridors into the Lower Mainland and Vancouver Island continues to be a major concern for B.C. Hydro. Given public concerns about electromagnetic field effects, visual impacts, and the natural environment, B.C. Hydro is undertaking programs which involve regional and local agencies and the general public to develop strategies to increase

the opportunities for utilizing existing corridors to the maximum extent possible and developing new corridors if they are required.

Planned Transmission Developments

It is anticipated that approximately $2.7 billion will be required for transmission system reinforcement over the next ten years.

Voltage Control Equipment - Static var compensator (SVC) installations are planned for service at Dunsmuir Substation on Vancouver Island in 1993, and at Ingledow Substation in the Lower Mainland in 1997. They will increase the power transfer capability of the Interior to Lower Mainland transmission system. Shunt capacitors are planned at various other substations serving the Lower Mainland and Vancouver Island over the next few years; timing and location will depend on actual electrical consumption patterns and on the timing and location of other system reinforcements.

Selkirk to Washington Water Power 230 kV Intertie - This intertie project is scheduled for 1995 to allow direct electricity trade between B.C. Hydro and Washington Power of Spokane, Washington, with no requirement for wheeling through the BPA system.

Kelly Lake to Cheekye 500 kV - A second 500 kV transmission line is proposed for service in 1996 between Kelly Lake and Cheekye Substations. An application for an Energy Project Certificate is scheduled to be submitted to the Minister of Energy, Mines and Petroleum Resources in April of 1991. This line would be the first 500 kV transmission line constructed from the Interior into the Lower Mainland in 20 years.

Nicola to Meridian 500 kV - Preliminary studies indicate that by about 1999, additional transmission capacity will be needed to meet forecast increased consumption in the Lower Mainland and on Vancouver Island and to continue to maintain system reliability. More detailed studies and public discussion are planned to determine if a second 500 kV transmission line from Nicola to Meridian Substation would be the best alternative.

Ingledow to Kidd 230 kV - A new 230 kV line from Ingledow Substation in Surrey to Kidd #2 Substation in north Richmond is proposed for completion in 1995/96. It will improve the supply capacity to customers in south Vancouver and Richmond.

Vancouver Supply - Additional 230 kV extensions are planned to meet load growth in Vancouver: a new circuit to Mainwaring Substation in South Vancouver in 1996; and a new underground cable circuit from Horne Payne Substation on Boundary Road in Burnaby to Murrin Substation in downtown Vancouver in 1999.

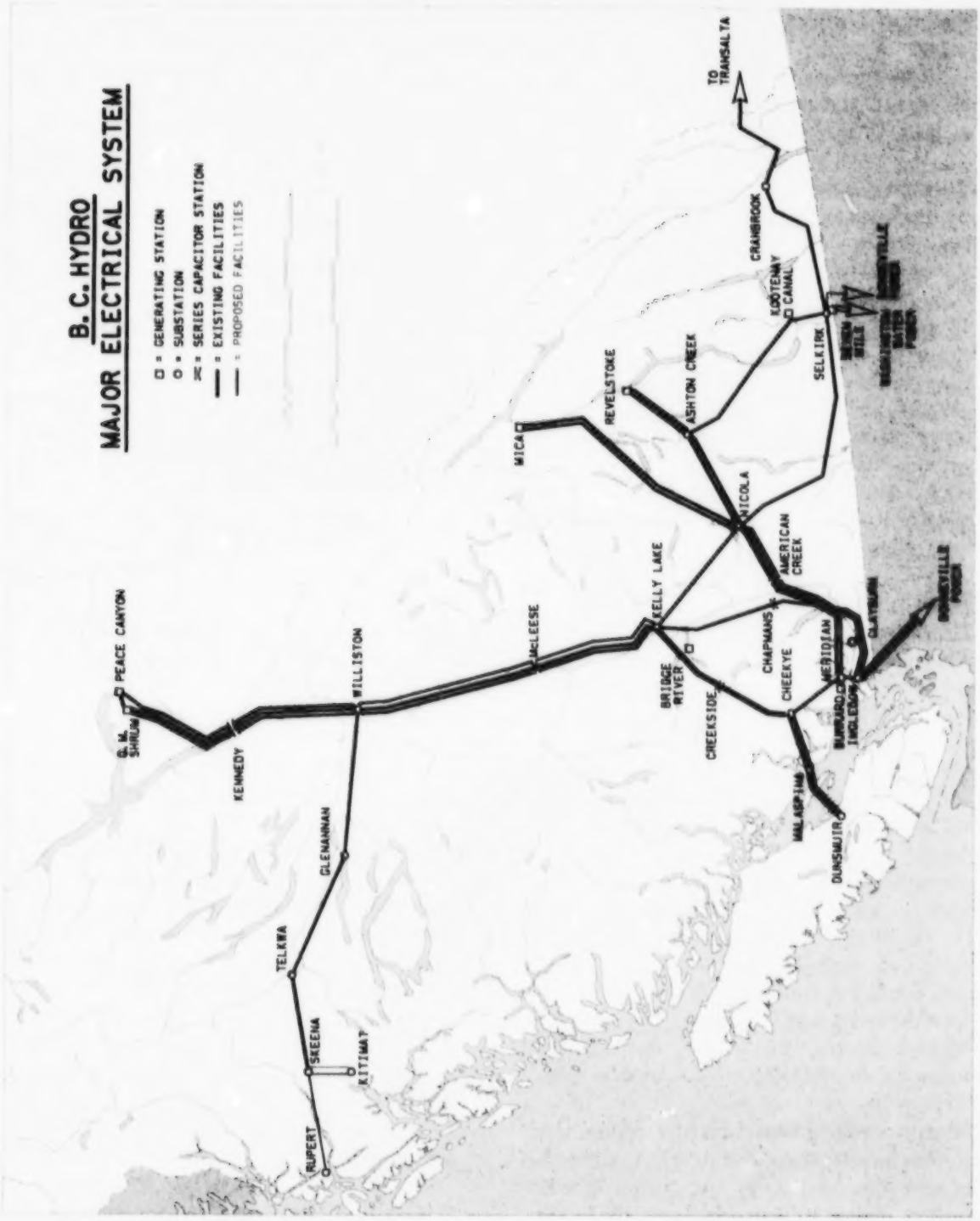
Fraser Valley Supply - A new 500/230 kV transformer installation and a 500 kV connection from a nearby existing circuit are planned at Clayburn Substation near Abbotsford in 1994 to reinforce the Fraser Valley supply network.

Vancouver Island Supply - A new 230 kV transmission line, proposed for the late 1990's, to be initially operated at 138 kV, should strengthen supply south of Nanaimo.

South Interior Supply - New 230 kV and 69 kV lines are planned for 2000 between Cranbrook, Invermere and Golden. These lines would increase the supply capacity to those areas to meet growing customer requirements.

North Coast and Central Interior Supply - A second 138 kV transmission line is planned for 1994 from Telkwa Substation near Houston to Smithers Substation. This line would provide a firm supply to the community of Smithers as well as to a proposed coal mine development near there.

Exhibit 5-1


B.C. HYDRO
MAJOR ELECTRICAL SYSTEM
□ = GENERATING STATION
○ = SUBSTATION
= SERIES CAPACITOR STATION
= EXISTING FACILITIES
= PROPOSED FACILITIES
TO TRANSALTA
CRANBROOK
KOOTENAY CANAL
SELKIRK
REVELSTOKE
ASHTON CREEK
MICA
NICOLA
AMERICAN CREEK
KELLY LAKE
McLEESE
WILLISTON
PEACE CANYON
G.M. SHRUM
KENNEDY
GLENANNAN
TELKWA
SKEENA
KITIMAT
RUPERT
BRIDGE RIVER
CREEKSIDE
CHAPMANS
CHEEKYE
MERIDIAN
DUNSMUIR

6.0 RISK MANAGEMENT

Conceptually, the discussion of risk management included in the 1990 Electricity Plan still applies. This section outlines specific risk issues relevant to the current outlook for future electricity demand and supply.

The planning process should be viewed in the context of long-term trends. Actual electricity demands and supplies will not coincide with the assumptions made for planning purposes. Key in this process is to differentiate between short-term variations which may balance out over the long-term, and the emergence of new, long-term trends. For example, if a particular sector of the economy were to experience favourable or unfavourable market conditions, an assessment must be made whether these conditions are likely or unlikely to be sustainable in the long-term for technical, economic or political reasons.

This plan includes resources and initiatives with sufficient flexibility to be able to respond appropriately to short-term variations. Measures which could be applied to adapt to short-term variations include appropriate reservoir management (eg. deliberate filling or drafting of reservoirs), variations in non-firm energy purchases, adjustment of interruptible electricity exports, and adjustment of existing thermal plant use.

In addition, this plan has considered several significant contingencies for variations in long-term trends. Before responding to variations in long-term trends with substantial irreversible commitments, full use would be made of available short-term measures. By bringing projects like Peace Site C and Keenleyside to shelf-ready status, the response time to meet stronger than expected demand growth is reduced, thereby permitting better use of short-term measures. In addition, short lead time projects such as gas turbines could also be brought to shelf-ready status by completing siting and obtaining permits well ahead of need.

Due to Demand Uncertainty

For the past three years actual electricity requirements have come in above forecast. While it has been argued that this could be the emergence of a long-term trend, recent data suggests some slowdown in various areas of the economy. If this slower growth trend continues, B.C. Hydro would further delay commitments to new projects (either private or utility-developed), and would market electricity surpluses whenever beneficial to do so.

If higher than expected demand growth occurs, B.C. Hydro could call on projects which are now at the shelf-ready stage. For example, if the forecast trend were to increase to what is now identified as the 75th percentile, electricity requirements would be about 5 800 GW·h/a higher after 10 years. In this event, a new project such as Peace Site C could be required as early as 2002. Alternatively B.C. Hydro could commit to a more aggressive IPP program to contract an estimated additional 600 MW by 2000.

Lower demand growth would result in decreases in non-firm purchases, delays in commitment to B.C. Hydro or private sector projects, and lowering of incentives to Power Smart and self-generation projects.

Due to Resource Uncertainty

Since the development strategy proposes to significantly increase B.C. Hydro's reliance on IPPs, self-generators, and resources not directly controlled by the utility such as the DSBs, the various risks associated with these sources of supply must also be managed. To examine the impact of the unexpected loss of

a significant resource, the sensitivity of the need for new resources has been studied, based on various possible scenarios for the return of the DSBs as outlined in section 3.5. If the DSBs were used to meet demands from projects currently not included in the B.C. Hydro forecast, the need for new resources would be advanced two to three years. If only half the DSBs were utilized for such purposes, new resources would be required about one year earlier than under the base assumptions. Alternatively, for either of these possible outcomes Peace Site C could be scheduled for service to replace the DSBs.

Due to Cost of IPPs

As outlined in section 4.0 B.C. Hydro's development strategy in the long-term is heavily reliant on IPPs. One of the possible risks of this approach is a strong positioning for IPPs, which could exact lucrative contract terms and prices from B.C. Hydro. Alternatively, for reasons and circumstances not foreseen today, the quantity of competitively priced IPPs envisaged as part of the development strategy may not become available. Projects that B.C. Hydro currently has at the shelf-ready status could provide a valuable hedge against undue risk exposure resulting from this strategy. For example, by adding Peace Site C in about 2005 the contribution from new IPPs to the end of the 20-year period would be cut in half.

7.0 ACTION PLAN FOR 1991/92

The following actions will be undertaken during fiscal year 1991/92 to advance implementation of this Electricity Plan update.

Power Smart Programs

Promotion of Power Smart programs will continue in 1991/92 and will build upon initiatives started in 1988 and 1989. About $53 million has been allocated for Power Smart programs in 1991/92. The costs and practicality of achieving program targets will continue to be evaluated from both the societal and utility perspective. Detailed analysis of the impact of these programs on B.C. Hydro's electric system operation will be undertaken.

The Collaborative process to determine electricity conservation potential in the B.C. Hydro and West Kootenay Power service areas should see completion of the first phase, i.e. definition of the technological, social, and economic potential by early 1992. The second phase, covering achievable potential should be complete by late 1992.

Resource Smart

Investments will be made to improve the output of B.C. Hydro's existing generation system. A capital budget of $10.5 million plus an additional $1.5 million for studies and investigations has been allocated to Resource Smart for 1991/92.

Discussions with Cominco to reach agreement on expansion of the Waneta and Brilliant projects will continue in 1991.

A decision on the investments required to achieve optimum system contribution from Burrard Thermal will be sought in 1991.

Purchases and Coordination

B.C. Hydro will pursue studies of further coordinated operation of the Columbia River system with the Bonneville Power Administration.

B.C. Hydro and TransAlta expect to sign an agreement on principles for coordinated operation with the Alberta Interconnected System in the spring of 1991. A potential sale of 200 MW of capacity to TransAlta and a similar amount of transmission access to U.S. markets should be resolved during the year.

Independent Power Producers

B.C. Hydro expects to finalize discussions with IPP proponents for the Integrated system in the Stewart/Meziadin, Fraser Canyon and Vancouver areas for over 100 MW of new capacity. In addition, an RFP should be issued for small thermal generation covering woodwaste and landfill gas projects.

Self-Generation

A major thrust for 1991/92 will be to conclude negotiations with a number of self-generation proponents. B.C. Hydro will continue to actively assist its major customers to evaluate their self-generation potential and to encourage development in this area, to take advantage of these load displacement opportunities as they become available.

New Capacity

The potential for capacity benefits in the B.C. Hydro system from installation of additional units at Mica or Revelstoke, or advancement of Lower Columbia Resource Smart projects will be assessed during 1991/92.

Alternative Energy

B.C. Hydro will be reviewing its alternative energy strategy to determine the future role of these resources in its Electricity Plan. Numerous technological and economic

changes have occurred since a strategy was last developed in the mid-1980's. A project team including representatives from B.C. Hydro, Powertech, and Canadian Electrical Association (CEA) R&D will be formed to coordinate development and implementation of such a strategy.

B.C. Hydro and Powertech's role vis a vis hydrogen, in particular with regard to its potential use in fuel cells, will be evaluated. Funding of a fuel cell demonstration program may be undertaken.

Major Transmission Projects

Work has begun on the third Williston to Kelly Lake 500 kV transmission line, with a fall 1994 scheduled in-service date. A second Skeena to Kitimat 287 kV line is also planned for completion in the fall of 1994. Both of these projects are necessary to provide firm transmission capability for the purchase of power from Alcan's Kemano Completion Project.

An application for an Energy Project certificate for the second Kelly Lake to Cheekye 500 kV transmission line will be submitted in April 1991. This line is needed by about 1996 to serve the continuing load growth in the Lower Mainland and on Vancouver Island.

Upgrade of the Peace 500 kV transmission system continues and should be completed in 1992.

Total expenditures of about $167 million are budgeted in 1991/92 for transmission system reinforcements.

Rate Design

A Public Hearing into a proposal by B.C. Hydro to modify the existing rate structure to encourage efficiency in the production and utilization of electricity will be held during 1991.

Export Activities

B.C. Hydro and Washington Water Power Company will continue planning of a 230 kV transmission intertie between their two systems. Construction of the line is subject to Powerex and Washington Water Power establishing sales agreements.

Public Consultation

The "Lower Mainland Choices for the Future" public consultation program, aimed at developing a shared understanding of issues related to electricity supply with the public and other external stakeholders in governments will take place during 1991, to review demand and supply options for the Lower Mainland.